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April 5, 2012

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek NOx BART Analysis

Dear Mr. O'Clair:

We are herewith responding to your letter of February 28, 2012, in which you requested that Great River Energy ("GRE") provide additional information to assist the North Dakota Department of Health ("NDDH") with its ongoing Best Available Retrofit Technology ("BART") determination for Coal Creek Station ("CCS"). You requested that GRE address some issues with its year 2000 visibility modeling, verify certain costs and data related to various pollution control options, and address some inconsistencies between GRE's cost analysis and the U.S. EPA's Control Cost Manual for certain cost components.

Enclosed is GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"), which provides a supplemental BART analysis that addresses the issues raised in the February 28, 2012 letter (as well as issues raised in your January 19, 2012 letter). In particular, GRE asked Barr Engineering to rerun the visibility modeling analysis as requested by NDDH. The revised visibility modeling, reflected in both Table 3.2 and Appendix D of the BART Supplement, demonstrates that the incremental visibility improvement of adding SNCR to Units 1 and 2 is essentially non-existent at only 0.106 deciviews. The BART Supplement also includes additional cost information from URS addressing your questions about the EPA Control Cost Manual and URS's departures from assumptions that EPA makes about costs. Barr Engineering also has included the cost/economic analyses regarding the impact of ammonia contamination on fly ash marketability and disposal costs based upon information provided by Golder Associates. Those costs are reflected in Table 3.1 of the BART Supplement. The costs reflect the expected costs depending on whether 0%, 30% or 100% of the fly ash becomes unmarketable due to ammonia contamination. Barr Engineering concluded that, even if no costs are attributable to ammonia contamination, installing SNCR on to already existing or planned controls would reduce NOx emissions at Unit 2 at a rate of $4,688/ton and $8,534/ton at Unit 1. Thus, SNCR remains well outside the range of cost-effective control technologies.

Since your February 28, 2012, letter, the U.S. EPA has issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ______(April __, 2012) ("EPA FIP"). In the EPA FIP, the Agency rejected NDDH's BART determination for CCS and imposed a NOx emission limitation of 0.13 lbs/mmBtu, based on EPA's determination that a combination of low-NOx burners and selective non-catalytic reduction ("SNCR") is BART.

GRE's analysis of the EPA FIP, EPA's basis for rejecting the NDDH BART for CCS, and EPA's own BART determination is also enclosed. See *Legal and Technical Review of U.S. EPA's BART Determination for Coal Creek Station* ("FIP Analysis"). The FIP Analysis concludes that EPA's rejection of NDDH's BART determination is ill-founded and EPA's own BART determination is severely flawed and inconsistent with the Clean Air Act and EPA's own regional haze regulations. EPA rejected NDDH's BART because of its cost analysis, primarily NDDH's reliance on certain cost values resulting from ammonia contamination of fly ash. GRE has corrected that value. EPA also questioned the retrofit factor for SNCR at CCS, but gave no basis for rejecting the factor applied by URS, GRE's consultant. On the basis of these two issues, EPA rejected NDDH's BART determination and substituted its own judgment for NDDH's regarding all five BART factors. The FIP Analysis addresses EPA's critique of the prior cost analysis and demonstrates that the cost of SNCR remains prohibitively high, particularly in light of the other four BART factors.

The FIP Analysis also examines EPA's own BART determination and concludes that it is severely flawed. EPA's cost analysis failed to consider the existing NOx controls at CCS in conducting its cost analysis and expressly ignored the incremental costs of installing SNCR beyond the existing and planned LNC3+ burner controls at CCS. Both of these decisions directly violate the statute and are inconsistent with EPA's guidelines and regulations. The effect of these two decisions is to greatly distort the actual cost-effectiveness of SNCR. Second, EPA utterly ignored the lack of any demonstrated visibility improvement that would result from investing tens of millions of dollars to install and operate SNCR. The EPA visibility modeling indicates that the greatest potential visibility benefit resulting from installation of SNCR would be 0.105 dv, which is only one-tenth the level that EPA asserts is discernable by the human eye. Additionally, given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of around 0.1 dv between options may reflect no real difference at all.

The FIP Analysis also demonstrates that EPA's conclusion that SNCR can be operated in a manner to avoid any fly ash contamination is unsupported. EPA's assertion that SNCR can be operated with a 2 ppm ammonia slip or less is not supported by the literature and studies EPA cites. Further, Golder Associates demonstrates that, even at a 2 ppm threshold, there will be significant fly ash wastage due to ammonia contamination. Consequently, the actual costs of utilizing SNCR will almost certainly be even higher and EPA's disregard of the collateral environmental impact of its BART selection is unjustifiable.

GRE's revised BART analysis provided today includes a refined cost analysis that examines the average and incremental cost, and cost-effectiveness, of various levels of NOx emissions control as well as a revised visibility impact analysis of various levels of control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost of less than $2,500 per ton. The actual incremental cost of SNCR will be in excess of $4,500 per ton for Unit 2 and over $8,000 per ton for Unit 1, even if no costs are assigned to the loss of merchantable fly ash. The actual costs will be even higher.

GRE greatly appreciates NDDH's continued work on the CCS BART. Please do not hesitate to contact me or my staff if you would like to discuss any of these matters in greater detail.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosures

c: William M. Bumpers, Esq.
Eric Olsen, GRE
Deb Nelson, GRE

resourceful. naturally.
engineering and environmental consultants

BARR

TRANSMITTAL LETTER

To:	Mary Jo Roth (GRE)	**Date:**	April 5, 2012
c:	Deb Nelson (GRE), Diane Stockdill (GRE), Joel Trinkle (Barr)		
Project #:	34280013.01	**Re:**	GRE CCS Supplemental NOx Analysis
Sent by:	Laura Brennan	**Phone:**	952.832.2615

We are sending you:

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These are transmitted as checked below:

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___	For your use	___	For review and comment:		

Description:

This report is a revised version of the original November 2011 report titled "Best Available Retrofit Technology Refined Analysis for NOx Emissions" submitted by GRE to the NDDH. The report reflects the collaborative effort of Barr and GRE with assistance from other technical consultants to develop an appropriate control strategy for Coal Creek's Units 1 and 2. Barr assisted with the development and update of cost estimates for various control scenarios, incorporating GRE's work with URS and Golder into the technical discussion at GRE's direction.

The Refined NOx Analysis is prepared in response to comments from the NDDH provided in letters dated January 19, 2012 and February 28, 2012. The conclusions and text of the analysis are not markedly changed in responding to NDDH's comments. The changes in this report primarily focus on updated modeling results and clarifications to cost calculations, as described below.

In response to an anomaly identified in Appendix D of GRE's submittal, GRE has revised the visibility tables that were presented in that submittal. A review of the modeling output files for the year 2000 SNCR run in question concluded that the values presented in the original table were consistent with the output files. The original modeling runs had been conducted in 2006 and 2007 for the initial BART evaluation, and the intermediate data files were no longer available to identify whether the apparent error was the result of an incomplete annual model run or some other contributing factor. In order to be responsive to NDDH's request for clarification of the data, the model was re-run. The modeling files had not previously been reopened for the NOx refined analysis efforts in 2011 and 2012. Accordingly, GRE also took the opportunity to more closely realign the NOx emission rates and stack-related modeling input parameters with the scenarios described in the report for all scenarios in all years as opposed to the approximations from previously modeled scenarios shown in the November 2011 tables.

The new results more closely align with the expected reductions for each control scenario and follow the trend originally illustrated in the year 2001 and 2002 tables for the February 10, 2012 submittal. The revised modeling runs support the conclusions presented in the GRE NOx analysis, and have only resulted in minor revisions to Table 3.3.1 and Appendix D.

In this revised report, NDDH also provides several comments with respect to alignment of calculations and clarity of documentation provided in the Appendix A cost calculations. Footnotes and documentation are appropriately updated. Additionally, the calculation alignment is clarified through the inclusion of additional significant digits. Neither of these updates result in changes to the final cost tables included within the report text.

Should you have any questions regarding this transmittal or the revisions herein, please contact Laura Brennan at 952.832.2615.

GREAT RIVER ENERGY®

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Coal Creek Station Units 1 and 2

Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

Coal Creek Station Supplemental BART Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limitations for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP), and issued a draft Permit-to-Construct (PTC) for these BART limits. As part of their review on North Dakota's draft and final SIP, EPA requested supplemental data and documentation on Coal Creek's BART controls. These requests started in February 2010, and continued through June 2011 and July 2011. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx controls for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE has performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to ash re-use on Coal Creek's Units 1 and 2. This supplemental analysis is being provided to address questions from the NDDH per its letters of January 19, 2012 and February 28, 2012.

Based on the supplemental analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/MMBtu, and is consistent with cost effective thresholds as set by North Dakota and ultimately approved by EPA through their partial approval of the North Dakota SIP. When all factors are adequately considered, including ammoniated ash impacts, SNCR is not considered cost effective for Coal Creek and would not result in perceptible visibility improvements in the affected Class I areas.

This supplemental analysis summarizes updated SNCR cost and emission assessments and supplemental information provided by URS Energy and Construction (URS). It also provides an updated ash implication assessment and supplemental information as provided by Golder Associates (Golder). (see Appendices F and G, respectively) The updated ash implications are then integrated with the updated SNCR cost and emission estimates to more accurately demonstrate that SNCR is not cost effective, by either EPA established thresholds or NDDH established thresholds.

1.1 Initial BART Analysis and EPA Guidance

In preparing the initial BART analysis and subsequent revisions, Great River Energy developed a combination of detailed engineering and screening level analyses, which were ultimately used by NDDH to make their BART determinations. From the BART preamble, EPA sets presumptive levels based on their cost effective assessments and deciview reductions, and essentially rule out post combustion NOx controls for electric generating units greater than 750MW, subject to the state's determination. Great River Energy's screening level analyses on SNCR and ash impacts initially supported EPA's presumptive determination. Great River Energy continues to concur with EPA's establishment of a presumptive NOx emission limit at 0.17 lb/MMBtu.

Specifically, in its final rule publication of 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, EPA establishes presumptive NOx levels based on combustion controls, and not SNCR:

> *In today's action, EPA is setting presumptive NOx limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, <u>States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.</u>* (emphasis added)

> *For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology; thus the NOx limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning.*

We are establishing presumptive NOx limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however, that some EGUs may not have adequate space available. In such cases, other NOx combustion control technologies could be considered such as Rotating Opposed Fire Air (''ROFA''). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air (''ROFA''), which has already been demonstrated on a variety of coal-fired units. <u>Based on the data before us, the costs of such controls in most cases are less than $1500 per ton.</u> (emphasis added)

The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NOx emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. <u>As a result, we believe our analysis and conclusions regarding NOx limits are conservative. For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination</u> (emphasis added).[1]

There are several key concepts from EPA's preamble. First, Coal Creek is unique in that it has installed DryFining™ as a novel multi-pollutant control technology. This is important because it enhances the effectiveness of the NOx combustion controls. Second, Coal Creek re-uses the vast

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[1] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134-39135.

majority of its fly ash rather than disposing of it. Any negative impacts to fly ash, such as adding ammonia, will have both operational risks and cost implications for Great River Energy that must be included in any cost-effectiveness determination. Third, EPA has made its cost-effectiveness determination in setting presumptive BART NOx levels and has given states the authority to determine if more stringent requirements are needed based on their review.

In reviewing EPA's preamble discussion, it was clear to GRE that the EPA did not expect BART control scenarios for tangentially-fired units, such as Coal Creek Station's Units 1 and 2, to include post combustion add-on controls such as selective catalytic reduction (SCR) and SNCR. As such, in the initial BART evaluation, GRE focused on supporting this determination through the use of screening level cost data, and comparing those screening costs to cost effectiveness thresholds.

Based on the direction provided in the BART preamble and guidance, along with an analysis of cost effectiveness thresholds implemented in other EPA regulatory programs,[2] GRE proposed a cost effectiveness range of $1,300 to $1,800 (2006$) per ton of NOx removed. Guidance provided by NDDH presented higher cost per ton thresholds than EPA's in setting the presumptive level.

GRE's BART NOx determination for CCS Units 1 and 2 was consistent with EPA's preamble and confirmed that advanced combustion controls and an emission limit of 0.17 lb/MMBtu represented BART. SNCR was found to be cost ineffective based on screening level analysis, and presented additional operational and non-environmental impacts that were not exhaustively discussed in the December 2007 BART analysis but are provided herein.

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[2]http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/Coal%20Creek/Coal%20Creek%20BART%20Analysis.pdf (Appendix B).

2.0 Refined NOx Control Evaluation at CCS

This section will first establish that Coal Creek is unique, such that site specific evaluations are more appropriate than relying on general screening level assumptions to determine emission reductions and associated costs. It will then summarize the evaluation of site specific SNCR NOx reductions by URS, as well as ash impacts from the ammonia associated with this control.

2.1 Unique Aspects of Unit 1 and 2 NOx Controls

As discussed in the following sections, Coal Creek Station is neither average nor typical. EPA Guidelines, provided to States in identifying appropriate Regional Haze control requirements and provided in EPA's Pollution Control Cost Manual (2002), are developed in order to assist State authorities in making regulatory determinations. These guidelines are not to be viewed as regulatory requirements. They are best suited for evaluating average or typical installations. Units 1 and 2 are uniquely designed and employ a state-of-the-art lignite fuel enhancement technology, or DryFining™. This means that any accurate analysis of add-on NOx controls must be site specific and not rely upon general guidelines, which might apply to a normal facility.

2.1.1 DryFining™ Technology

GRE has a long track record of being innovative and going beyond minimum environmental requirements. DryFining™ is a $270 million, multi-pollutant technology. It reduces coal moisture and impurities while increasing the heat content of Fort Union lignite, which has the highest moisture of any coal in the US. The operation of DryFining™ has afforded CCS Units 1 and 2 significant reductions across the spectrum of emissions. Sulfur dioxide and mercury emissions have been reduced by more than 40%. Carbon dioxide emissions have been reduced by 4%. NOx emissions – the subject of the EPA FIP and this evaluation – have been reduced by more than 20%.

GRE expected that some additional NOx reductions would result from the implementation of DryFining™. It was estimated that the reduction in coal moisture, and corresponding increase in coal heat content, would result in less coal into the furnace, and more air available elsewhere in the furnace, which can be utilized to reduce NOx emissions. However, this NOx reduction benefit was not quantified in the original BART analysis. At the time of the final BART analysis (December 2007), DryFining™ had not yet operated, and the exact degree of control was unknown for this innovative strategy. Because DryFining™ has been in place for nearly two years, NOx emissions are reduced. Consequently, current (baseline) NOx emissions that are used in Section 3.1 have been updated to reflect the URS control cost analysis and are inclusive of DryFining™, with low NOx burner technology as applicable.

2.1.2 NOx Combustion Control Considerations

GRE's proposed BART NOx control strategy includes the use of DryFining™ along with advanced combustion controls. As a result of the installation of the proposed advanced combustion controls on Unit 2, GRE has gained a better understanding of anticipated NOx control levels and costs.

The size and arrangement of the furnace box on CCS Units 1 and 2 is unique. It is literally a one-of-a-kind furnace box, sized specifically for the high moisture Fort Union lignite. Given a larger firebox, relative to other lower-moisture, higher-heat-content coal-fired units, there is a correspondingly higher complexity and higher cost to NOx combustion controls. There is a greater distance across the furnace through which the air must penetrate, thus increasing the size and type of wall nozzles, along with increased nozzle staging complexity throughout the wall sections. When an advanced combustion air system is added to a larger firebox, it requires additional wall openings, and redesign to wall water tubes, further increasing costs.

Since the time of the initial BART submittal, GRE has gained direct operational experience on the performance of these advanced combustion controls and DryFining™. Prior to the installation of DryFining™, most of the available primary air was needed to convey, grind, and dry the coal in the pulverizers due to the high moisture in the coal. Consequently, the maximum performance for the LNC3+ control installed on Unit 2 could not be fully realized upon initial installation. The Unit 2 LNC3+ installation includes larger registers to increase available primary air. Since a significant amount of that primary air was used to dry and pulverize the "unrefined" high moisture coal, there was not sufficient air available for the larger registers to act as a form of overfire air. With DryFining™, there is additional air available to be routed to the larger registers, which reduces NOx emissions. As a result, Units 1 and 2 currently operate with annual average NOx emissions of 0.200 and 0.153 lb/MMBtu, respectively. Unit 2's lower annual average NOx emission rate is directly attributable to the larger registers, which are tentatively anticipated for Unit 1 in 2014.

2.1.3 Site Specific SNCR Expected Control Levels

Portions of Coal Creek Station's December 2007 submittal of the NOx BART analysis were based on screening level data presented in the EPA Pollution Control Cost Manual (2002). Since EPA has proposed to reject North Dakota's SIP largely on their assessment of SNCR's screening level, cost effectiveness, it is imperative to more accurately portray SNCR costs. With respect to SNCR specifically, EPA acknowledges in its cost manual:

> *SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required [normal stoichiometric ratio] NSR are not published in the technical literature. Furthermore, the design is highly site-specific. In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required NSR and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling.*[3](emphasis added)

As discussed above, GRE has established that Coal Creek is unique due to its boiler size, DryFining™, and existing NOx combustion controls. Therefore, only a site specific evaluation, by a competent engineering and construction company (URS) familiar with SNCR engineering and installation costs, should be used to estimate emission reductions and associated costs. URS is a leading engineering consultant, with significant experience in installing SNCR technology, having managed the design and installation of several dozen SNCR pollution control systems throughout the world. This experience qualifies URS to make site-specific recommendations on SNCR design.

URS completed a site inspection, evaluated the unique aspects of Coal Creek, and provided their refined analysis (see Appendix B).

URS has determined that the removal efficiency for Coal Creek Unit 1 with an inlet NOx concentration of 0.22 lb/MMBtu would not be 50% as anticipated from the EPA Pollution Control Cost Manual (2002), and as used in GRE's original BART analysis. Rather, URS estimates a removal rate of approximately 30% removal for Unit 1. With respect to Unit 2, and an inlet concentration of 0.15 to 0.16 lb/MMBtu, URS estimates the removal efficiency would be approximately 20%.

EPA has raised concerns with respect to utilizing a new baseline period in determining the removal efficiencies for SNCR vs. DryFining™ with LNC3+. At the time of the 2007 BART analysis, GRE had no experience with the DryFining™ technology and was unable to determine the removal efficiencies possible with the LNC3+ and DryFining™ projects combined relative to NOx emissions.

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[3] EPA Pollution Control Cost Manual (2002); Section 4.2 Chapter 1.3.

In an effort to evaluate existing installed technologies, GRE incorporated actual DryFining™ operating experience and performance subsequent to the 2007 analysis. This information must be considered in the revised analysis in order to capture the actual realized removal efficiencies of the DryFining™ and LNC3+ technologies as existing installed pollution control technologies. GRE notes that since the submittal of the 2007 BART analysis, GRE has lowered its Unit 2 NOx emissions from the baseline level of 0.22 lb/MMBtu to 0.153 lb/MMBtu on an annual average basis. This equates to an emissions reduction of 30.5% from the previously utilized 2007 baseline.

In addition to GRE's experience operating CCS with LNC3+ in combination with the DryFining™ technology, resulting in lower NOx emission levels, a relatively new study has been completed for a facility with low-baseline NOx emissions[4] (Appendix E). This EPRI study addressed applicability of and anticipated removal efficiencies for SNCR for units with low-baseline NOx emissions. The study's findings suggest that SNCR performance is significantly decreased at baseline NOx emission levels less than 100 ppm[5]. The demonstrated low removal efficiencies (~10% reduction) are much lower than GRE's suggested removal efficiency for the SNCR technology (20%) applied in this analysis. Similarly, the low removal efficiencies are also much lower that the removal efficiency of 25%+ suggested in EPA's proposed FIP.

The study concludes that for low-baseline NOx applications, at levels around 75 ppm4, anticipated removal efficiency for SNCR is in the range of 8%-12%. If GRE takes into account the data from this study in place of the removal efficiency recommended by URS, the cost effectiveness would be well outside the range deemed cost effective. GRE's anticipated SNCR removal efficiency of 20% is likely higher than the technology will be able to achieve starting from a baseline of 0.153 lb NOx/MMBtu or 88 ppm (DryFining™ with LNC3+ installed). GRE continues to use a removal efficiency of 20% in its analysis based on the SNCR technology evaluation conducted by URS, but notes that this value may in fact be conservatively optimistic.

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[4] *Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration*: *Joppa Unit 3*. EPRI, Palo Alto, CA: 2009, 1018665. GRE asserts a business confidentiality claim and asserts this report is confidential business information subject to the protections set forth in Air Pollution Control Rules for the State of North Dakota at 33-15-01-16 and 40 CFR Part 2.

[5] Current NOx concentrations for CCS Unit 1 and Unit 2 are 110 ppm and 88 ppm, respectively (determined on a 12-month rolling average basis).

Given these lower projected emission rates, and the lower "baseline" emission rates from installed controls, the cost evaluation has been revised, accordingly, in Section 3.1.

Rather than relying on the original screening level analyses, GRE finds it imperative to provide this updated information to North Dakota to make their well-informed cost effectiveness determinations.

2.2 Revision of Baseline NOx Emissions

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." To accurately depict the anticipated annual emissions for the units at CCS a new baseline must be established taking into consideration the DryFining™ technology and installed combustion controls in Unit 2 (LNC3+). The DryFining™ process is designed to remove moisture and segregate dense material from the coal prior to introduction of the coal into the final stage of grinding and conveyance into the boiler. DryFining™ having been funded under a DOE collaborative agreement (DE-FC26-04NT41763) was required to conduct performance tests which demonstrated a heat input reduction of approx. 2-3%. Having removed the moisture prior to the introduction into the pulverizers lends to less primary air required to "dry" and convey the coal through the pulverizers, making air available for staging (Over-fired air NOx control) in other areas in the boiler. This drier coal will not require the same amount of heat input into the boiler because wet coal expends some of its heat input to vaporize the moisture in the coal and its heating value has increased per pound so fewer pounds are needed. Thus a drier coal will not require that additional coal typically lost to vaporizing the moisture and reduced heating value. DryFining™ is currently obtaining a moisture reduction in the coal of approximately 8%. Future tuning is continuing and will meet a required reduction of 12% by 2016, which is needed for the SO_2 BART analysis to achieve full scrubbing.

In order to make its cost effectiveness determination, North Dakota must not only have site specific control cost, but also accurate emission reduction estimates. Clearly, with the installation of both LNC3, LNC3+, and DryFining™, Coal Creek's NOx emissions are greatly reduced with respect to "baseline" values previously provided. In this section, in light of recently refined analysis, GRE will update baseline emissions to be used in making the cost effectiveness determination.

Based on the timing of the original analysis, the initial BART evaluation used baseline emission rates for approximately the same time period that was used to determine the visibility baseline, which was a 5-year period of emission inventory data from 2000 to 2004. It is necessary to update the baseline emissions for Units 1 and 2 for this technology evaluation in order to reflect current conditions and unit performance. Both units utilize "low NOx coal-and-air nozzles with close-coupled and separated overfire air," which is referred to as LNC3. Since the time of the initial evaluation, NOx controls in the form of larger registers,[6] advancing the LNC3 controls (LNC3+),[7] have been added to Unit 2, which means that the two units have different baselines for the purpose of estimating future emission reductions. For Unit 1, the revised baseline is 0.200 lb/MMBtu, as an annual average. For Unit 2, the revised baseline is 0.153 lb/MMBtu, as an annual average, as also described in Section 2.1.2. These new "baseline" emission rates are lower than the initial BART baseline of 0.22 lb/MMBtu.

2.2.1 Circumferential Cracking in Boiler Tubes

Following the installation of LNC3+ technology at Unit 2, CCS has determined that an emission rate of 0.15 lb/MMBtu for LNC3+ is not a sustainable 30-day rolling average control level due to circumferential cracking. In other words, the 0.15 lb/MMBtu on a 30-day rolling basis is at the edge of this technology's capabilities. While GRE may intermittently achieve this rate on a monthly or perhaps more easily as an annual average, it is not the basis for a 30-day rolling limit.

As background, in 2008 GRE lowered NOx emissions from Unit 2 by expanding the OFA registers. This diverted more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. NOx emissions were lowered, but there was an unexpected side effect. This low NOx emission rate caused circumferential cracks in the boiler tubes between the burner front and the over-fired air registers.

The phenomenon of circumferential cracking has several interrelated contributing factors including high surface temperatures (>900°F bare tubes, >1100°F weld overlays) (which exposes the boiler tubes to high wall temperatures and high temperature fluctuations, which produces numerous thermal fatigue cracks in the boiler walls), frequent and severe thermal spikes (>100°F), and corrosive

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[6] Larger registers allow for a greater ability to tune combustion staging and thus control NOx emissions.

[7] LNC3 is the acronym used by EPA to describe a specific type of restrictive combustion control. To differentiate between the controls installed on Unit 1 and the additional controls installed on Unit 2 (both are versions of LNC3), the acronyms LNC3 and LNC3+ are used for each unit, respectively.

conditions/deposits. Low NOx burner systems with overfire air ports produce longer flames and increase the chance of flame impingement and local overheating of the boiler walls.

In 2009, Coal Creek Station began to experience unscheduled outages on Unit 2 due to failures from the circumferential cracking described above. To understand and correct this problem, Great River Energy engaged the Electric Power Research Institute (EPRI) to assist in evaluating the causes and potential remedies for this problem. To date, corrective actions have included detailed examinations of the boiler tubes to detect the extent of the cracking, the installations of additional temperature monitors to determine boiler wall temperatures, the replacement of damaged boiler tubes, and continued tuning of the boiler to minimize the circumferential cracking in the zone of concern. While not eliminating the problem, these efforts have greatly reduced the problem of unscheduled outages caused by circumferential cracking. Based on our analysis, it is not clear how to completely and consistently eliminate this problem, while operating at or near 0.15 lb/MMBtu on a 30-day rolling basis. Efforts continue to further reduce this circumferential cracking problem while balancing our desire to operate at lower NOx emission levels.

The only examples of tangentially-fired units with emissions lower than the 0.17 lb/MMBtu NOx presumptive level are facilities with post combustion NOx controls, such as SNCR. Further, a majority of these SNCR controlled sources operate well above the 0.17 lb/MMBtu, as annual averages, as detailed in the Cross State Air Pollution Rule and illustrated in Figure 2.2. Consequently, GRE presumes it cannot safely and consistently operate below 0.17 lb/MMBtu as a 30-day rolling limit, without installing SNCR.

2.2.2 Load Variability

In addition to circumferential cracking, this assessment must also consider load variability and its impacts on NOx emissions. The NOx emission limits proposed in the original BART evaluation for Units 1 and 2 did not consider that Coal Creek's units would experience significant load variability. GRE has historically operated as a baseload unit, without much load swinging. In May 2011, Midwest Independent Transmission System Operator (MISO) began cycling CCS in the real-time market. In September 2011, GRE greatly increased the cycling range of CCS in response to current market prices in the MISO market. This is important because load swinging significantly impacts expected NOx control performance. While base load NOx emissions can be tuned due to relatively stable load, the swinging load cannot be finely tuned but must still be accounted for when assessing compliance with emission limits.

Table 2.1 illustrates the variability experienced during recent load swinging. It is different on Units 1 and 2, due to different NOx controls. Based on changing market conditions, load variability is expected to continue as an operational scenario for Units 1 and 2 for the foreseeable future. As such, any emission limit must account for this additional variability in emissions. It is clear from Table 2.1 that the BART NOx presumptive emission rate of 0.17 lb/MMBtu is achievable, including load variability, and also reflecting the maximum NOx emission reductions from LNC3+ and DryFining™, as demonstrated through Unit 2.

Table 2.1 Coal Creek Station NOx Emission Rates During Load Variability

Scenario Description		NOx Emissions (lb/MMBtu)			
		Unit 1		Unit 2	
		Min	Max	Min	Max
Overall - Nov. 2010 to Nov. 2011	30-day Rolling	0.179	0.219	0.14	0.169
Load Variability – May – November 2011	30-day Rolling	0.186	0.219	0.146	0.166
	Hourly Average	0.206		0.16	
Load Variability – September – November 2011	30-day Rolling	**0.207**	**0.219**	**0.163**	**0.166**
	Hourly Average	0.218		0.17	

In addition, GRE provides a chart (Figure 2.1) showing Unit 2's 30-day rolling average NOx emission rate, with notes on tuning emphasis and load variability, as further support of the 0.17 lb/MMBtu emission limit.

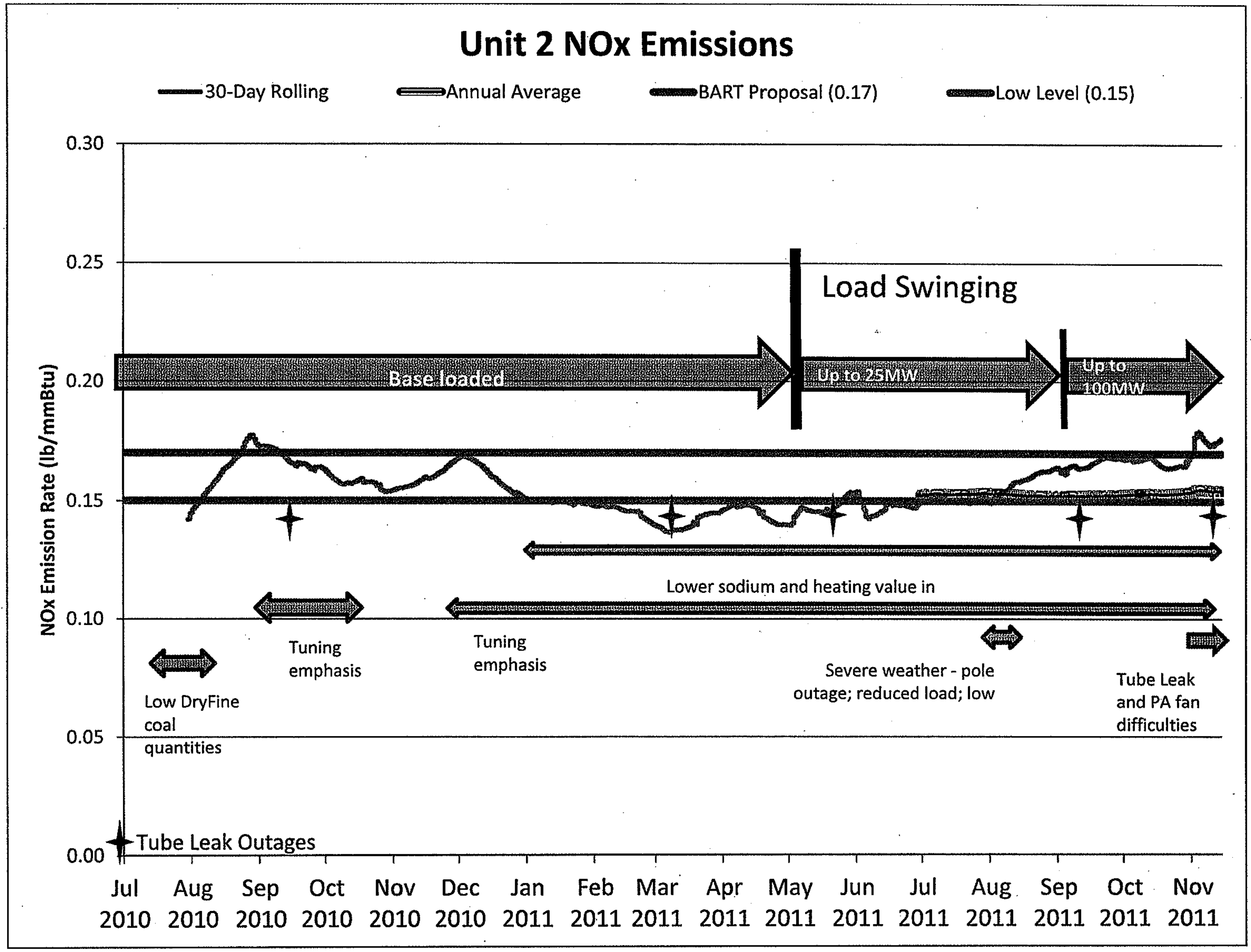

Figure 2.1 **Unit 2 30-Day Rolling NOx Emission Averages**

2.2.3 Evaluation of SNCR Effectiveness in CSAPR

Interestingly, the Coal Creek presumptive NOx BART emission rates are consistent with annual average emissions as modeled by EPA in CSAPR. By reviewing existing units of similar design, data from the docket for the proposed Cross State Air Pollution Rule (Docket ID EPA-HQ-OAR-2009-0491) illustrates that there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and SNCR post combustion controls that operate at or below the presumptive BART limit of 0.17 lb/MMBtu for NOx (Figure 2.2), as annual averages. If the data set is expanded to include LNC3 ("low NOx coal-and-air nozzles with separated overfire air (LNC2[8])") and "low NOx burners and overfire air (OFA)" as illustrated in Figure 2.3, only four supercritical[9] emission units operate below the presumptive NOx limit of 0.17 lb/MMBtu. None of the facilities included in the CSAPR database operate at or below the proposed FIP limit of 0.12 lb/MMBtu. All of the facilities analyzed use SNCR to effectively achieve the Coal Creek presumptive NOx emission limit of 0.17 lb/MMBtu. To state it differently, Coal Creek effectively achieves presumptive BART with DryFining™ rather than SNCR.

[8] LNC2 and LNC3 are various types of low NOx burner design.

LNC2 = Low NOx burner with separated OFA

LNC3 = Low NOx burner with close-coupled and separated OFA

[9] For a subcritical boiler (standard operational design consistent with CCS Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation point and then isothermally heating of the system causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, lower emissions.

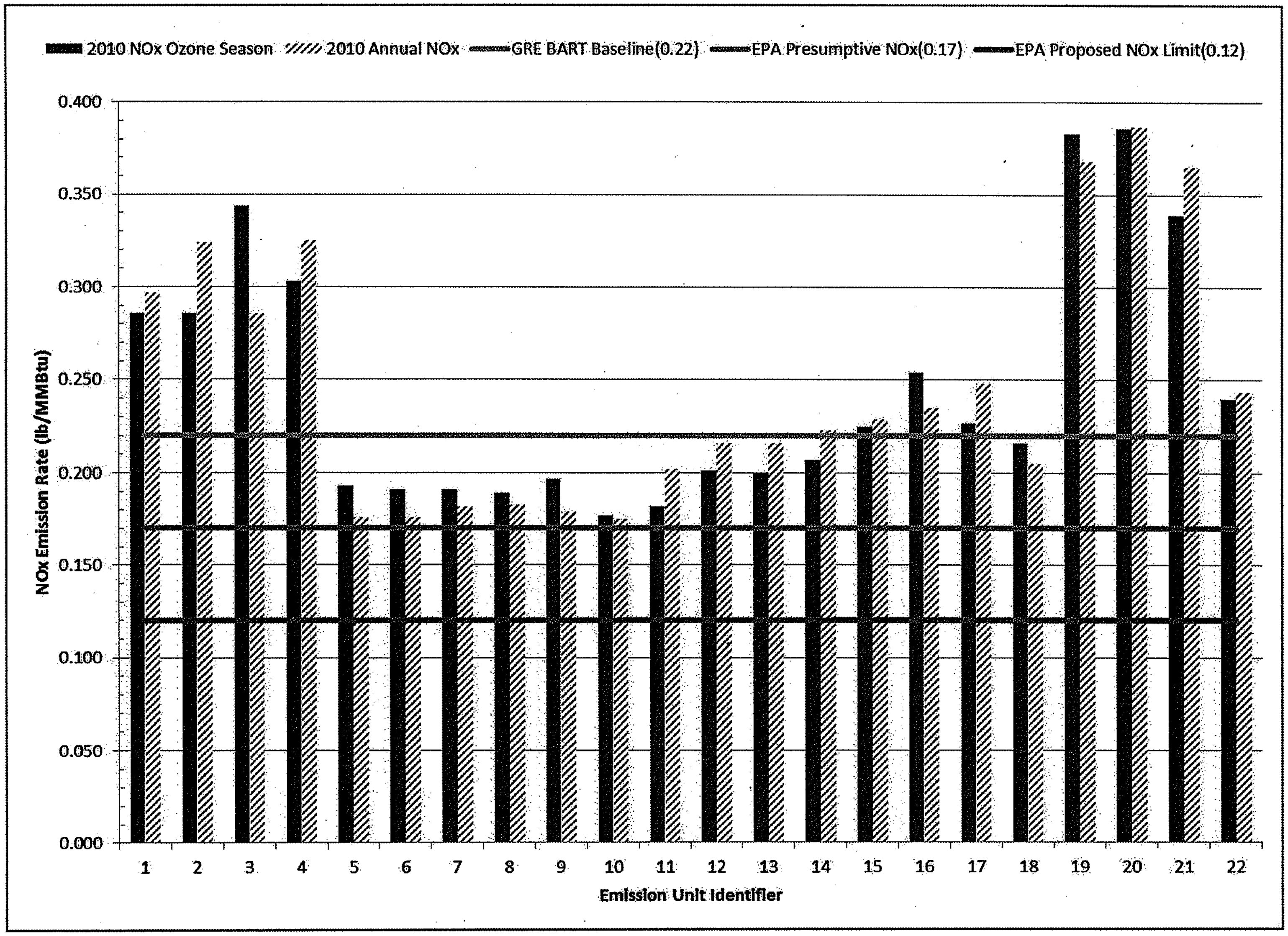

Figure 2.2 **2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC3/OFA NOx Control**

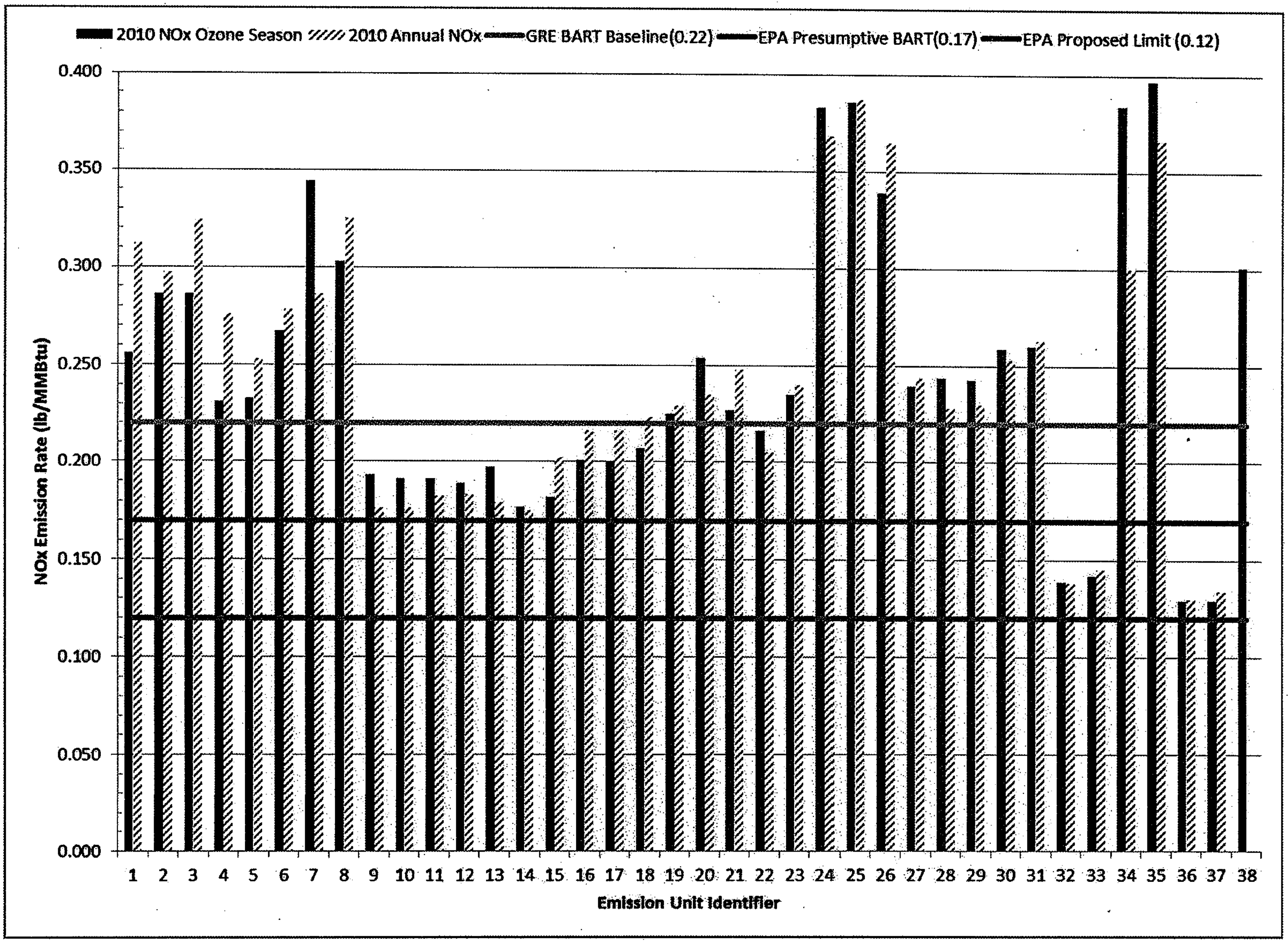

Figure 2.3 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC2/LNC3/OFA NOx Control

2.2.4 Ash Cost Considerations

The EPA indicated in its proposed FIP that GRE fly ash sales and disposal values provided in previous submittals were in error and, when corrected, resulted in SNCR being cost effective. Great River Energy had previously submitted two estimates: $5/ton and $36/ton (2006$). Contrary to our Summer 2011 submittal, these values were not necessarily in error, but instead represented different assumptions on economic impacts of lost ash sales and associated disposal costs. Therefore, rather than rely upon these screening level values as previously submitted, GRE contracted with Golder Associates to provide a more refined analysis of ash impacts associated with the installation of SNCR. The following discussion and attached "Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation" (Appendix C) provides a more comprehensive assessment of ash implications associated with SNCR installation.

To provide some additional background on the previously submitted values, the $36/ton value represented the total freight on board (FOB) Coal Creek Station price that was paid by the end user. The $5/ton dollar per ton figure represented what GRE received as a portion of the FOB price prior to December 1, 2011.

Both of the values ($5/ton and $36/ton) attempted to capture lost revenue from decreased ash sales. In each case, an additional $5/ton cost was added as GRE's cost to dispose of the unsalable ash. This additional $5/ton disposal value was the result of a screening level analysis and had not taken into account all of the internal costs associated with ash disposal. This disposal value also had not accounted for anticipated cost increases based on changing ash disposal regulations, nor did it take into account various ash disposal levels as could be anticipated due to lost fly ash sales.

GRE and Headwaters Resources, Inc (HRI), GRE's strategic partner in the sales and distribution of fly ash, have invested heavily into fly ash sales infrastructure including terminals and storage facilities, conveying equipment, scales and train car shuttles. HRI financed GRE's portion of the infrastructure through a per ton payment on fly ash sales. The current ash sales contract requires payments to GRE that total 30% of the $41 (2011$) FOB price or $12.30 per ton (2011$) of ash that is delivered.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case

100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

2.2.5 SNCR's Impact on Ash Management Options

Fly ash from CCS is used throughout the Upper Midwest to replace a portion of Portland cement in concrete production, making the concrete more durable and longer lasting. Ash generated at Coal Creek Station has chemical and physical properties that make it an extremely desirable ash in the concrete market. Coal Creek Station currently generates approximately 525,000 tons of fly ash per year. Approximately 415,000 tons of that ash is sold as a Portland cement replacement. Coal Creek fly ash has been used in many large-scale projects such as construction of the new Interstate-35W Bridge after its collapse.

The beneficial use of fly ash also has a strong positive economic benefit to Great River Energy, and the regional economy. We started selling fly ash nearly three decades ago. In that time, we have grown this activity into a sizable annual revenue stream. The addition of SNCR will have a negative impact on the marketability, value and perception of Coal Creek Station's fly ash. The addition of ammonia into the combustion process leaves an ammonia residue on the ash that can cause aesthetic and worker safety issues during the use of the ash. The residual ammonia in the ash eventually off-gases and creates odors which are offensive, are potentially dangerous to human health, and can even pose an explosion risk. Section 1-2 of EPA's Pollution Control Cost Manual recognizes this fact and states the following:

> *Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH levels. Under these conditions, ammonia gas can release into the atmosphere. These results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. <u>Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the</u>*

salability of the ash as a byproduct and the storage and disposal of the ash by landfill.[10](emphasis added)

The range of residual ammonia left with the fly ash can vary with each installation of SNCR. Ammonia slip of only 5 ppm, generally accepted as the minimum that can be achieved with SNCR, can render fly ash unmarketable. (URS, Appendix B) Even in those systems where residual ammonia is generally low, there will be times of increased ammonia slip based on plant operations. As the plant output varies due to market demand or startup/shutdown activity, varying levels of ammonia will be used to control NOx and, consequently, the levels in the ash will change. Variable ammonia levels in the ash create additional complexity to both sales and/or treatment, and will result in increased disposal.

2.2.6 Ammonia Mitigation Technology

Great River Energy is committed to ash re-use due to its economic and environmental benefits. Therefore, we anticipate additional capital and operating costs to treat the ash in order to ideally preserve a percentage of ash sales. With respect to ammoniated ash treatment, Ammonia Slip Mitigation (ASM) technology refers to a variety of technologies that have been designed to improve the marketability of ammoniated ash. These technologies fall into two rough categories, combustion or carbon burn out (CBO) and chemical treatment. CBO is the process of running the ash through an additional combustion unit that would combust and burn out the residual carbon and ammonia that is with the ash. This is a capital intensive technology that also has high operating costs. The second category of ASM technology is generally referred to as chemical treatment. These treatment technologies involve creating a chemical or physical reaction that results in the off-gassing of the residual ammonia. These treatment technologies are generally less costly than CBO. For purposes of this more refined analysis, GRE contracted with Golder Associates to provide a detailed cost estimate of one particular chemical treatment technology as a potentially cost effective option. The detailed cost estimate can be found in Appendix C.

Even with a cost effective ASM technology installed, there will be times when the residual ammonia levels in the ash are too high to treat. Ammonia injection rates will vary during periods of startup and shutdown, in addition to variable load operation, in order to maintain compliance with the BART limits. Variable ammonia injection rates and associated changes in ash concentrations will result in

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frequent testing and periodic rejection of ash for on-site disposal. Further, variable ammoniated ash levels will put GRE's generated ash in a very vulnerable position with respect to competitors in the fly ash marketplace, reducing ash sales and increasing on-site disposal.

2.2.7 Ash Disposal Scenario Cost Summaries

Appendix C contains a technical assessment and cost analysis of ammonia slip mitigation technology and ash disposal under RCRA Subtitle D design standards. To address the uncertainty regarding costs associated with ammoniated ash management and disposal, a range of costs is presented. These costs are based on three scenarios described below. Table 2.2 shows the volumes of ash produced, sold and disposed of in each scenario. For a more detailed description please see Appendix C.

Scenario A (current ash sales levels) – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to maintain 100% marketability. (Golder 2011) This hypothetical scenario is not considered to be a possible option for future ash management costs but serves as a point of reference for understanding future impacts.

Scenario B (No ash sales) – This "worst case" scenario assumes that the ammonia slip impact of SNCR makes fly ash at CCS completely unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

***Scenario C* (30% sales reduction, ASM costs)** – This "realistic" scenario assumes that Headwater's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales levels due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

Table 2.2 Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

It is clear in EPA's proposed FIP that the installation of SNCR may negatively impact ash sales[11].

Our knowledge of the ash marketplace, SNCR systems, and treatment technologies confirm that the installation of SNCR will have a detrimental impact on the salability of fly ash. GRE believes that Scenario A, which represents no impact to ash sales, is extremely unlikely. Nevertheless, we present it as a point of reference for better quantifying the ash impacts from SNCR installation.

GRE believes that scenario B (zero ash sales) is a likely outcome, but we hope that through investment in ASM technology we will be able to preserve some of the ash sales. To model partial ash sales, we created Scenario C. Scenario C assumes an investment in ASM technology and a reduction of ash sales by 30%.

It is not possible to determine exactly what percent of ash sales would be lost based on the installation of the SNCR and ammonia mitigation technologies at Coal Creek Station. There are no plants in the country with both of these technologies operating together on a lignite-fired unit. In fact, the vendor responsible for the ammonia mitigation technology will not guarantee the technology's performance at Coal Creek Station.

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[11] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011 / Page 58620.

"Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal."

Across the country there are examples of plants that have SCR or SNCR and sell most of their ash, however, there are also others that sell none of their ash. It is a very site-specific scenario and depends on the type of coal, type of combustion, type of ash collection, plant operation (cycling % load), type of ammonia mitigation technology (if any), and how the SNCR or SCR system has been designed, installed and implemented. Each and every site is very different.

For the sake of modeling the costs related to lost ash sales we determined it was important to model a middle ground between 0% lost ash sales and 100% lost ash sales. There is a strong possibility that all ash sales will be lost and a zero chance that 100% ash sales will be maintained; some middle option needed to be considered. We looked across the industry to determine the best scenario for a moderate outcome. The 30% lost ash sales figure reflects a reasonable and optimistic (i.e., conservative) outcome that can be justified based on our understanding of plant operations and the ash markets in which we compete for sales.

The only plant (Eastlake) in the U.S. operating with the discussed ammonia mitigation technology operates under a very different scenario. This plant mixes the ammoniated ash with a non-ammoniated ash prior to sales. Thus, Eastlake is able to sell up to approximately 85% of its ash. However, Coal Creek Station is unlike the Eastlake plant. Increased load variation at CCS, adjusting plant output to match the MISO market in which we operate, can lead to upsets in the SNCR system and higher levels of ammonia in the ash.

The addition of ammonia mitigation technology and additional handling and processing steps will also increase the cost of ash to the end users. As our price point in the market increases, we will face increased competition and will lose some sales to competing ash sources.

In addition, consistency is a prized trait for a fly ash that is marketed to the cement industry. The addition of SNCR will have a detrimental impact on the consistency of the market product. Decreased consistency will lead to lower demand for the ash and will result in some lost sales to competing ash sources.

Predicting exactly what impact all of these factors will have on our ash sales is not possible. Based on our investigation and knowledge, and that of the experts we consulted, we concluded it is very likely that we will lose 50% or more of our ash sales. We chose to model 30% loss in sales as a conservative scenario that likely underestimates the real impact of this technology on ash sales.

Furthermore, in our modeling scenarios, we assumed that the future regulation of coal ash would not be subject to RCRA Subtitle C requirements. Consistent with our comments to EPA's docket during its Coal Combustion Residuals rulemaking, we believe Subtitle C regulation of coal ash is unwarranted and unnecessary. Nevertheless, EPA has proposed it as one option for a final rule. Subtitle C regulation of coal ash would significantly increase our cost to handle and dispose of our ash. Subtitle C regulation has not been included in our scenarios.

In summary, we consider a 30% scenario to be a very optimistic view of the future that relies on the successful implementation of a technology that cannot currently be guaranteed by the vendor and has never been installed on lignite-fired units. This scenario also quantifies increased disposal costs, in addition to some GRE-specific economic benefit from preserved ash sales. None of the scenarios attempt to capture economic impacts to GRE's strategic partners or other regional entities, but these impacts are mentioned in Section 3.2 and should also be taken into consideration when making a final BART determination.

2.2.8 Ash Management Costs

There are three major cost categories to be considered in each of these scenarios;

- Fly ash disposal cost estimates,
- Ammonia slip mitigation costs, and
- Lost fly ash sales revenue

Each cost area is summarized below. For a more detailed assessment, see Appendix C.

2.2.9 Fly Ash Disposal Cost Estimates

Given significant uncertainty with pending regulatory requirements such as RCRA Subtitles C and D, with ammonia slip treatment technologies, and with market reactions to ammoniated ash, Great River Energy has developed essentially three scenarios that attempt to capture a range of possibilities associated with SNCR installation. For all three scenarios, a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE, as GRE does not currently have a suitable location for siting a Subtitle D landfill. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, this varies between 2.2 million and 10.5 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity.

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS. (Golder 2011)

Table 2.3 Disposal Cost Summary (2011$)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Total Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000
Incremental Increase in Disposal Cost Compared to Scenario A ($/ton) *	-	$7.40	$5.44

*These values are used in the BART analysis as they represent the only the incremental costs above the baseline costs which would be incurred with or without the installation of SNCR.

2.2.10 Ammonia Slip Mitigation Costs

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 2.4. (Golder 2011)

Table 2.4 ASM Post-Processing Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

2.2.11 Lost Fly Ash Sales Revenue

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 2.5. (Golder 2011)

Table 2.5 Lost Fly Ash Sales (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

2.2.12 Total Fly Ash Management Costs

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 2.6. This table represents the total economic impact of SNCR installation on GRE's fly ash management in two likely scenarios; a total loss of ash sales and a 30% reduction in ash sales.

Table 2.6 **Total Fly Ash Management Costs (Golder 2011)**

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

2.2.13 BART Analysis Ash Disposal Cost Summary[12]

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on the detailed technical review discussed above and included as Appendix C, GRE proposes a range of ash disposal costs and lost ash sales revenue figures in the BART analysis. None of the scenarios consider the significant cost impact of potential RCRA Subtitle C regulation in the future.

Scenario B represents the highest cost scenario with a total annual additional cost of $8,988,000. The total cost includes lost ash sales revenue of $5,105,000 (Table 2.5) and an additional annual ash disposal cost of $3,883,000 or $7.40 per ton disposed (Table 2.3).

Scenario C represents an optimistically low cost scenario with a total annual additional cost of $4,435,000. The total cost includes lost ash sales revenue of $1,531,000 (Table 2.5) and an additional annual ash disposal cost of $1,275,000 or $5.44 per ton disposed (Table 2.3). Scenario C also includes a Ammonia Slip Mitigation cost of $5.61 per ton of ash reused for an additional annual cost of $1,629,000 (Table 2.4).

[12] All costs within this section are presented in 2011$.

3.0 Integrated NOx Control and Ash Impact Impacts Analyses

This section will integrate the revised baseline emissions, the refined URS SNCR Analysis and the Golder Ash Impact Analysis. It will then provide a summary table with associated cost per ton and incremental cost per ton values.

3.1 SNCR Control Cost Analysis

As discussed in Section 2.1.3, baseline NOx emissions are adjusted to reflect existing controls. Based on the updated baseline, Table 3.1 summarizes the anticipated control costs for additional NOx controls. It includes more refined SNCR costs for CCS Units 1 and 2 (See URS Report Appendix B). It also includes cost scenarios from the Golder Associates Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation (See Appendix C). It should be noted that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness (e.g., LNC3+ is evaluated at 0.153 lb NOx/MMBtu on an annual average basis with an anticipated 30-day rolling limit of 0.17 lb NOx/MMBtu). Costs are valued on a present (2011) dollars basis.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

Table 3.1 Control Cost Summary (2011$)

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (T/yr)	Installed Capital Cost ($MM)	Annualized Operating Cost ($MM)	Pollution Control Cost ($/ton)	Incremental Cost $/ton
	SNCR, LNC3+, 100% Lost Ash Sales (Scenario B)					$8.878	$5,821	$19,125
	SNCR, LNC3+, 30% Lost Ash Sales (Scenario C)	0.122	33%	1,525.2	$17.873	$6.602	$4,329	$13,762
Unit 1	*SNCR, LNC3+, No Ash Impacts (Scenario A)*					*$4.384*	*$2,875*	*$8,534*
	SNCR, 100% Lost Ash Sales (Scenario B)					$8.795	$7,629	
	SNCR, 30% Lost Ash Sales (Scenario C)	0.150	25%	1,152.8	$12.176	$6.519	$5,655	NA – Inferior Control
	SNCR, No Ash Impacts (Scenario A)					*$4.301*	*$3,731*	
	LNC3+	0.153	24%	1,100.9	$6.079	$0.763	$693	$693
	Baseline (LNC3)	0.200	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base
	SNCR, 100% Lost Ash Sales (Scenario B)					$8.115	$10,505	$10,505
Unit 2	SNCR, 30% Lost Ash Sales (Scenario C)	0.122	20%	772.5	$11.794	$5.839	$7,559	$7,559
	SNCR, No Ash Impacts (Scenario A)					*$3.621*	*$4,688*	*$4,688*
	Baseline – LNC3+	0.153	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base

Scenario A (No Ash Impacts) is provided for reference only and does not represent a feasible control option.

Below is provided the least cost envelope illustrated graphically. Only dominant controls falling within the least cost envelope were further analyzed for incremental feasibility. Inferior technologies are deemed not cost effective.

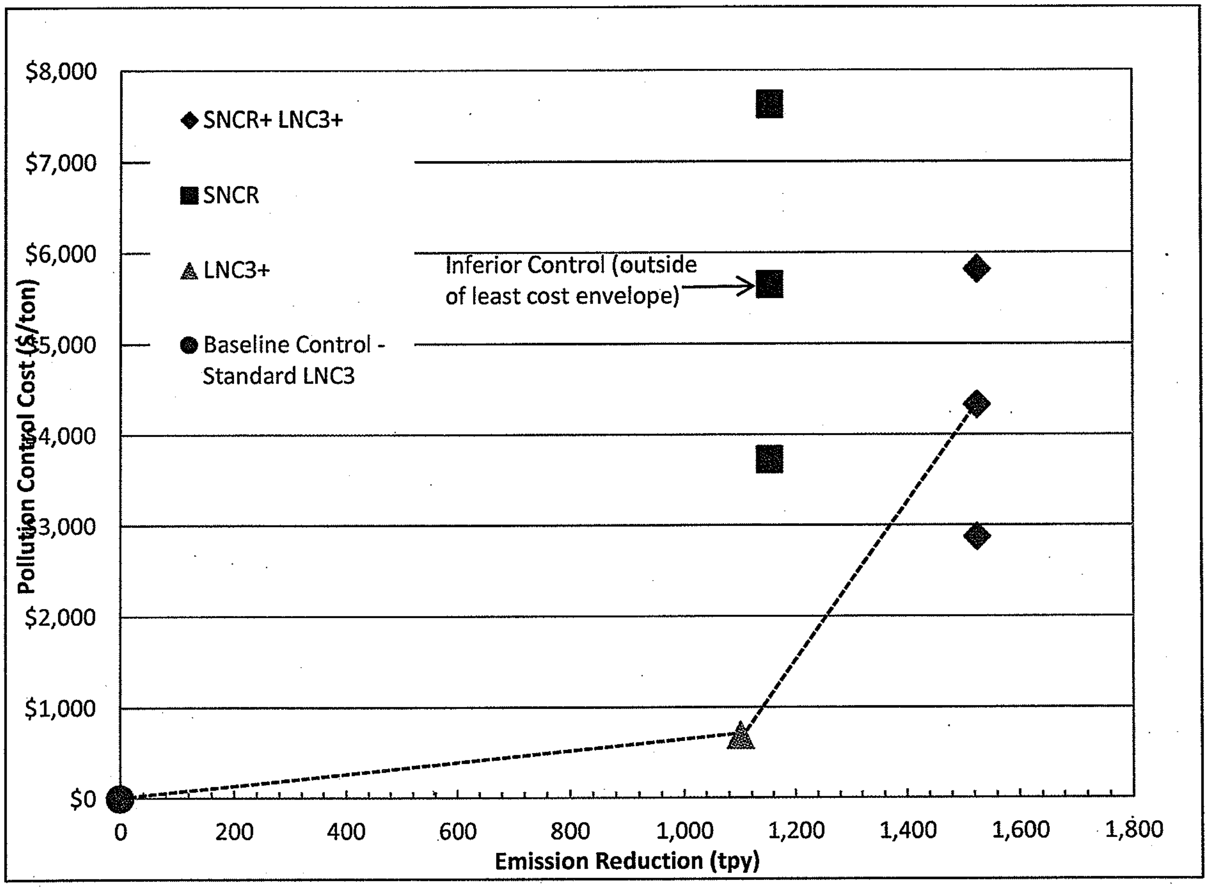

Figure 3.1 **Incremental NOx Analysis**

The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

This refined economic impacts analysis confirms GRE's original conclusion that SNCR is not a cost effective NOx control option. From Table 3.1, it would appear as if Unit 1 SNCR – No Ash Impacts would be cost effect on a dollar per ton basis according to the State of ND thresholds, but in understanding that this scenario is considered hypothetical since some level of ash impacts are expected, and the incremental cost per ton is an order of magnitude higher than anything deemed cost effective. The disparity in the incremental costs occurs due to the fact that the DryFining™ with LNC3+ technology could achieve the associated emissions reduction indicated for the SNCR technology. As highlighted, the "most realistic" or optimistic scenario is 30% lost ash sales, with cost exceeding $4,000 (2011$) per ton of NOx controlled. This value is higher than EPA's determination of economic infeasibility for SCR for CCS at around $4,000/ton (2011$) of NOx removed stated in the FIP.

Although not directly incorporated into GRE's capital and operating control costs presented above, NDDH must also consider additional impacts, such as indirect and stranded cost components discussed in Section 3.2 and Section 3.3.

3.2 Additional Impacts

GRE provides these additional impact considerations not found in the original BART analysis as important to North Dakota in making its final BART determination.

1. The use of DryFining™ technology that has already been implemented for use at both units at a cost of $270 million. GRE has made a significant investment to achieve multi-pollutant emission reductions and visibility improvements in the region.

2. At the time of this submittal, GRE has already installed LNC3+ combustion controls at Unit 2. In 2011 dollars, this was at a cost of over $6 million and has already resulted in NOx reductions. The same system is currently tentatively scheduled to be installed on Unit 1 during the 2014 outage.

3. Ash infrastructure investments of over $31 million have been made to date for management and sale of Coal Creek Station's ash. Over $7 million of the total investment have been made by GRE, directly.

4. The DryFining™ technology provides a dual emission improvement for the total BART analysis. In order to achieve 100% scrubbing for the SO_2 analysis GRE must reduce the moisture, related air flow and therefore the total mass of flue gas travelling through the absorbers in the scrubber. DryFining™ will be implemented to its fullest extent by the BART compliance deadline.

3.2.1 Regional Impact from Ash Sales Revenue

The BART analysis does not take into account additional regional economic impacts resulting from the reduction or elimination of CCS ash sales. In order to estimate these regional impacts, one can use the freight on board (FOB) price of the ash at $41 (2011$), and subtract GRE's share of that revenue at $12.30 (2011$). Therefore, SNCR installation would reduce or eliminate ash sales, eliminating an additional $28.70/ton (2011$) from the local and regional economy. This could result in a loss of as much as $11,910,500 (2011$) per year from the local and regional economy. In addition to these regional economic impacts, there are other impacts that must also be considered.

3.2.2 Fly Ash is Important to the National Economy

Fly ash is an important part of the regional and national economy. The National Association of Manufacturers reported in 2010 that Coal Combustion Residuals (CCRs) contribute $6-11 billion annually to the U.S. economy through revenues from sales for beneficial use, avoided cost of disposal, and savings from use as a sustainable building material.[13] The beneficial use of fly ash and other CCRs are directly responsible for a large number of jobs throughout the country. A 2011 report by Veritas found that "Approximately 10.6 million tons of coal combustion residuals were used in concrete-related products during 2009. Those products provided employment for 240,100 manufacturing workers, 78,480 foundation, structure, and building exterior workers and many of the 102,350 nonresidential building construction workers during 2010." (Veritas 2011[14])

3.2.3 Fly Ash is Important to Regional and National Infrastructure

The American Road and Transportation Builders Association[15] completed a report in 2011 that highlighted the importance of fly ash as a component of road and bridge construction across the country. Their research found that the elimination of fly ash as a construction material would increase the average annual cost of building roads, runways and bridges in the United States by nearly $5.23 billion. This total includes $2.5 billion in materials price increases, $930 million in additional repair work and $1.8 billion in bridge work. The additional costs would total $104.6 billion over 20 years.

3.2.4 Environmental Benefits of Ash Reuse

The use of fly ash as a replacement for cement has many environmental benefits. As a result of the increased use of fly ash, less land is disturbed for quarrying raw materials, less land is taken out of production for landfills, and less carbon dioxide (CO_2) is emitted into the atmosphere to make cement. Using one ton of fly ash instead of Portland cement reduces up to one ton of greenhouse gas emissions. Inversely, by contaminating the ash with ammonia, and increasing ash disposal, there will be a corresponding 1-to-1 ton increase in CO_2 emissions from using more Portland cement. These CO_2 emissions are not trivial.

[13]Report available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-6992.

[14] Available at: http://www.recyclingfirst.org/pdfs/101.pdf.

[15] Available at: http://www.artba.org/mediafiles/study2011flyash.pdf.

3.2.5 Additional Ash Management Cost Considerations

The ash management costs detailed in this report are considered to be conservative figures from reasonable assumptions that most likely underestimate GRE's future expenditures on ash management.

The ash analysis envisions that all future disposal facilities will be designed and constructed to RCRA subtitle D standards. EPA is currently proceeding with an ash disposal rulemaking that will create uniform national disposal standards under RCRA subtitle D, the far more stringent Subtitle C (Hazardous Waste), or some hybrid approach that takes some requirements from each Subtitle D and C. The cost of complying with a Subtitle C rule would vastly exceed the amounts discussed in this report. This analysis reasonably assumes Subtitle D.

The ash disposal costs discussed above are portrayed as three scenario costs: a baseline which represents current ash sales figures; a scenario where all ash must be disposed of; and a scenario where ash sales are reduced by 30% from the baseline. There is significant uncertainty regarding specific impacts to beneficial reuse if SNCR were installed. The zero ash sales scenario (Scenario B) is very possible and is an outcome that we hope to avoid. Scenario C captures a "hybrid" estimate of the future where some ash is beneficially used and some additional ash must be disposed. For the hybrid scenario, we chose a 30% reduction in sales. This 30% estimate is an optimistic figure of preserved ash sales at 70%. It is quite possible that the amount of ash requiring disposal could easily represent a 50%, 70% or larger reduction in fly ash sales. For this reason, Scenario C is likely to produce ash management costs that are lower than will actually be encountered.

As discussed above, there are a variety of different Ammonia Slip Mitigation (ASM) technologies available. Most of these technologies have only been installed at a small number of generating units and, to GRE's knowledge, no lignite-fired unit is currently operating SNCR and ASM technology.[16] Of all ASM technologies that were investigated, the Headwaters technology was the least expensive. If the Headwaters ASM technology fails to function properly on lignite, it is likely that we would incur significantly larger costs to preserve the beneficial reuse of some portion of our fly ash.

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[16] It is important to note that Headwaters ASM technical staff have stated that this technology has not been tested on a lignite unit and they would not guarantee any level of performance if installed at CCS.

The EPA Pollution Control Cost Manual (2002) does not allow GRE to include in our BART analysis the value of previously purchased assets that would be rendered useless by the elimination or reduction of fly ash sales. GRE and its strategic partner, Headwaters Resources, have invested $31 million on ash storage, transportation and distribution infrastructure.

3.3 SNCR Visibility Impacts

It is known that NOx contributes to ammonium nitrate formation, which is predominantly a winter "haze" contributor. For purposes of valuing the welfare effects of recreational visibility, it is important to consider that the North Dakota national parks are generally not in high use during the winter season. If required to install SNCR, GRE will pay an extreme price per deciview resulting in imperceptible improvements for a time of year when the parks are generally not used.

To satisfy EPA's proposed Federal Implementation Plan, Coal Creek Station would need to install SNCR technology to reach a NOx emissions level that is 29% lower than EPA's presumptive BART. Yet, the extensive modeling performed as part of the BART analysis concludes that the installation of SNCR, at an emission rate of 0.12 lb/mmBtu, will have an imperceptible improvement in visibility, ranging from 0.05 deciview (dV) to 0.18 dV in the Class I areas near the facility. This is far less than one-half of what EPA has determined to be perceptible to the human eye (0.50 dV)[17]. As such, it is not justifiable for GRE to incur the added cost of SNCR without any appreciable improvement in visibility.

It is worth noting that SNCR will result in ammonia emissions to the atmosphere. Ammonia is a listed state toxic in North Dakota, and is viewed as a contributor to regional haze because it can bond with sulfur dioxide and nitrogen oxides to form ammonium sulfate and ammonium nitrate aerosols Consequently, GRE does not believe that SNCR is a cost effective technology for improving visibility.

3.3.1 CCS Modeled Visibility Impacts

Under EPA's modeling guidelines, it is necessary to develop a 24-hour maximum anticipated emission rate for each control technology in order to assess visibility impacts. GRE assumes that on a 30-day rolling basis, combustion and post-combustion NOx controls can experience emissions that

[17] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.
FR discusses State's ability to consider potential impacts for VOC and ammonia although full analyses may not be required.

are approximately 10% higher than their annual design basis. Similarly, for assessing a 24-hour maximum emission rate, GRE assumes emissions will be up to 20% higher than the annual design rate for a given control.

GRE presented a full evaluation of anticipated cost per unit visibility impairment (Δ-dV) in its final BART analysis (Dec 2007). Pollutant interaction has an impact on modeled visibility impairment and, as such, GRE believes that modeling changes to NOx emission rates alone will not provide visibility modeling results that are representative of actual emission controls. This may overstate visibility improvement as compared to modeling NOx, SO_2 and fine PM together. However, for the purpose of illustrating the relative visibility impacts of SNCR and LNC3+, an analysis of the difference in modeled impacts is presented in Table 3.2.

An incremental cost per deciview analysis is also included in Table 3.2. This comparison relies on the annualized operating costs presented in Table 3.1, and represents the difference in annualized capital costs between the two controls compared to the change in average visibility impairment for the 98th percentile over the three modeled years for the same controls.

Table 3.2 Difference in Impairment and Incremental Cost for LNC3+ with Tuning and SNCR with LNC3+

Unit ID	2000 (dV)	2001 (dV)	2002 (dV)	Average (dV)	Incremental Cost per dV (MM$/dV)[1]
Unit 1	0.031	0.044	0.093	0.056	$103.81
Unit 1 & 2	0.062	0.083	0.172	0.106	$110.26

[1] Incremental cost comparison (2011$) of LNC3+ with SNCR with LNC3+ at 30% lost ash sales.

The visibility analysis demonstrates that SNCR will not result in actual improvement to visibility in North Dakota's affected Class I areas, and potential modeled improvements will come at a prohibitive incremental cost exceeding $100 million (2011$) per deciview. Utilities in North Dakota only contribute ~6% to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D.

4.0 Conclusions

Great River Energy provided BART Determinations utilizing the 5 step process in 2007. Until now, Great River Energy has provided screening level analyses and assumptions with respect to SNCR installation. Due to EPA's proposed FIP, and its assertion that SNCR is cost effective for Coal Creek Station, Great River Energy responds with more refined analyses in three primary areas. This refined analysis reevaluates the last two steps of the BART Determination process for LNC3+ and SNCR technology at Coal Creek Station.

First, URS provides a site specific evaluation of SNCR effectiveness at Coal Creek Station, which results in lower projected emissions reductions from this control. These emission estimates clearly change the basis for any cost effective determination. Consideration for startup and shutdown emissions, circumferential cracking and load variations should also factor into this determination as discussed in Section 2.2.

Second, URS reviewed and updated both capital and operating costs for SNCR, based on their expertise and site specific investigation. These values were relatively consistent with values presented to EPA in June and July 2011, but are somewhat higher than the screening values presented in the original BART analysis.

Third, Golder Associates conducted a detail ash impact analysis associated with a range of costs from contaminating the fly ash with ammonia from SNCR. While the exact impacts to Coal Creek Station's ash management and sales are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on a detailed technical review GRE would expect to incur additional ash annual costs somewhere between $4,435,000 and $8,988,000 (2011$).

The final two steps of the BART Determination include Step 4 - "Evaluate Impacts and Document Results" and Step 5 – "Evaluate Visibility Impacts". In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economic inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology. GRE included the visibility tables for the associated LNC3+, and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that based on our refined analysis the state Class I areas would not see any perceptible improvement in visibility by requiring a level of NOx control above LNC3+ for CCS, and additional reductions would be cost prohibitive on a dollar per deciview basis (Table 3.2).

When the three refined analyses of the final two steps of the BART Determination process are combined and evaluated, it clearly demonstrates that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

On strictly a cost effective basis, SNCR can be ruled not cost effective for Unit 2, especially when the GRE specific risks and costs associated with this technology are included. On an incremental cost effectiveness basis, SNCR can be ruled not cost effective for Unit 1, also considering the GRE specific risks and costs associated with this technology. As noted, there are additional economic and visibility impacts associated with SNCR that further preclude it from consideration.

Appendix A

Pollution Control Cost Evaluations

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
3 [2]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	33%	3,086.2	1,525.2	$17.873	$8.878	$5,821	$19,125	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.602	$4,329	$13,762	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.384*	*$2,875*	*$8,534*	*A-4, A-8*
2	SNCR - 100% Lost Ash Sales	0.150	25%	3,458.5	1,152.8	$12.176	$8.795	$7,629	NA - Inferior Control	A-7
	SNCR - 30% Lost Ash Sales						$6.519	$5,655	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.301*	*$3,731*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,510.5	1,100.9	$6.079	$0.763	$693	$693	A-4
0	Baseline Control - Standard LNC3	0.200	NA-Base	4,611.4	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
1	SNCR - 100% Lost Ash Sales	0.122	20%	3,089.8	772.5	$11.794	$8.115	$10,505	$10,505	A-10
	SNCR - 30% Lost Ash Sales					$11.794	$5.839	$7,559	$7,559	A-9
	SNCR - No Ash Impacts					*$11.794*	*$3.621*	*$4,688*	*$4,688*	*A-8*
0	Baseline Control - LNC3+	0.153	NA-Base	3,862.3	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B
[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.
[3] Calculated on a mass basis.
[4] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I			6015	MMBtu/hr	
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	7,700	7,700	7,635	7,599	7,629
Fuels Used:					
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07
MMBtu/hr	5,727	5,743	5,705	5,685	5,697
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203
Total Stack Emissions:					
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203

Baseline Emis	
Unit 1	**Unit 2**
7,653	8,410
3,311,405	3,688,805
0.64%	0.64%
6,373	6,373
43,708,554	47,761,077
5,712	5,679
95.0%	94.3%
0.200	0.153
4,378.8	3,642.5
1205.2	918.5
0.201	0.153

Equipment Information: GRE Coal Creek Unit II			6022	MMBtu/hr	
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.152	0.153	0.152	0.153	0.154

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 Study Year 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%
Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal						

Future Operating Scenario for BART Cost Analysis

Operating Information	Unit 1	Unit 2			Data Source	Notes
Annual Op. Hrs	7,652.6	8,409.6	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F			
Temperature	330.0	330.0	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,900	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,205.2	918.5			July 2010 to October 2011 Coal Creek Emission Data	
Max Emis (tpy)	4,611.4	3,862.3				
Baseline Emiss (lb/MMBtu)	0.200	0.153				

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx -	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		1,257,796
Purchased Equipment Total (B)		1,958,057
Installation - Standard Costs		1,958,057
Installation - Site Specific Costs		NA
Installation Total		3,729,632
Total Direct Capital Cost, DC		5,687,689
Total Indirect Capital Costs, IC		391,611
Total Capital Investment (TCI) = DC + IC		6,079,300
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	7,079
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)		763,210

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	24%			3510.5	1,100.9	693

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.
2. Total capital investment reflects actual installed costs for Unit 2 installation, inflated to 2011 dollars.
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Process, emissions and cost data listed above is for one unit.
5. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		1,257,796
Instrumentation		
Sales Taxes		
Freight		
Purchased Equipment Total (B)		1,958,057
Installation		
Foundations & supports		
Handling & erection		
Electrical		
Piping		
Insulation		
Painting		
Installation Subtotal Standard Expenses (1)		1,958,057
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Site Specific - Other	Site Specific	NA
Total Site Specific Costs		NA
Installation Total		3,729,632
Total Direct Capital Cost, DC		5,687,689
Indirect Capital Costs		
Engineering, supervision	5% of purchased equip cost (B)	97,903
Construction & field expenses	10% of purchased equip cost (B)	195,806
Contractor fees	0% of purchased equip cost (B)	0
Start-up	1% of purchased equip cost (B)	19,581
Performance test	1% of purchased equip cost (B)	19,581
Model Studies	NA of purchased equip cost (B)	NA
Contingencies	3% of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20% of purchased equip cost (B)	391,611
Ozone Generator, Installed Cost		0
Total Capital Investment (TCI) = DC + IC (2)		6,079,300
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		6,079,300
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Labor	37.00 $/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr	3,539
Maintenance Materials	100% of maintenance labor costs	3,539
Utilities, Supplies, Replacements & Waste Management		
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Total Annual Direct Operating Costs		7,079
Indirect Operating Costs		
Overhead	60% of total labor and material costs	4,247
Administration (2% total capital costs)	2% of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1% of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1% of total capital costs (TCI)	60,793
Capital Recovery	0.0837 for a 20-year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)		763,210

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0	Zero out if no replacement parts needed
Annualized Cost	0	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	0	Zero out if no replacement parts needed	
Annualized Cost	0		

Electrical Use							
	Flow acfm		ΔP ft H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	ΔP ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs				
Ozone Needed	1.8 lb O3/lb NOx	- lb/hr O3		
Oxygen Needed	10% wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2
LTO Cooling Water	150 gal/lb O3	0 gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf		
Circulating Water Rate	0 gpm			
Water Makeup Rate/WW Disch =	20% of circulating water rate =		0 gpm	
Scrubber Cost	10 $/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350 lb O3/day	$0 Installed	Installed cost factor per BOC.	

Direct Operating Cost Calculations

Annual hours of operation: 7,652.6
Utilization Rate: 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	96	0	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	96	3,539	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,539	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.0604	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.3100	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Cooling Water	0.3208	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.3671	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.9572	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.9581	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.0000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.1933	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.6100	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0000	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Caustic	364.4367	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.9108	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,465,600
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								12,176,084
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,282,068
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								4,300,954

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	3,731

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,700,000
Purchased Equipment Costs		
Instrumentation	10% of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28% of purchased equipment cost	1,036,000
Freight	5% of purchased equipment cost	185,000
Purchased Equipment Total	[redacted]	5,291,000
Purchased Equipment Total+ Retrofit Factor (A)		8,465,600
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,763,600
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	134,484
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	12,176,084
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		12,176,084
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	182,641
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310 See Direct Operating Cost Calculations on last pg.	8,256
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA	-
Total Annual Direct Operating Costs		3,282,068
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		4,300,954

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.08368

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5 years	
CRF	0.2342	
Rep part cost per unit	0 $/ft^3	
Amount Required	12 ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0	Zero out if no replacement parts needed
Annualized Cost	0	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2 years		
CRF	0.0000		
Rep part cost per unit	0 $/ft^3		
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	0	Zero out if no replacement parts needed	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0		

Electrical Use		kW
NOx in	0.20 lb/MMBtu	
NSR	0.60	
Power		[redacted]
Total		61.0

Reagent Use & Other Operating Costs			
NOx in	0.20 lb/MMBtu	Urea Use	[redacted] lb/hr
Efficiency	25%	Volume 14 day inventory	269 ton
Duty	6,015 MMBtu/hr	Inventory Cost	$134,484
Water Use	[redacted] gal/hr		

Direct Operating Cost Calculations

Annual hours of operation: 7,652.6

Utilization Rate: 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	$/kwh, 61.0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.31 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	7.18710	ton/hr	55,000	0	$/ton, 7.2 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,465,600
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								12,176,084
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,500,243
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								6,519,129

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	5,655

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,700,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,036,000
Freight	5.00% of purchased equipment cost	185,000
Purchased Equipment Total	[redacted]	5,291,000
Purchased Equipment Total+ Retrofit Factor (A)		8,465,600
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,763,600
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	134,484
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	12,176,084
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		12,176,084
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	182,641
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310 See Direct Operating Cost Calculations on last pg.	8,256
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	5.44 See Direct Operating Cost Calculations on last pg.	637,648
NA	NA	-
Ammonia Mitigation	5.61 See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	765,675
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA	-
Total Annual Direct Operating Costs		5,500,243
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		6,519,129

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			[redacted]
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	[redacted]	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	[redacted]	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	15.32159	ton/hr	117,250	637,648	5.4384 $/ton X 15.3216 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	18.98048	ton/hr	145,250	814,853	5.61 $/ton X 18.9805 ton/hr X 7652.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	8.13449	ton/hr	62,250.0	765,675	12.3 $/ton X 8.1345 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,465,600
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								12,176,084
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,775,768
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								8,794,654

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	7,629

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			3,700,000
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	[redacted]		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			8,465,600
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)		A + B + C	11,763,600
Allowance for Funds During Construction (E)		0 for SNCR	0
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)		Reagent Vol * $/gal	134,484
Intial Catalyst and Chemicals (I)		0 for SNCR	0
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	12,176,084
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			12,176,084
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			7,775,768
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)			8,794,654

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.08368

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5 years	
CRF	0.2342	
Rep part cost per unit	0 $/ft^3	
Amount Required	12 ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0	**Zero out if no replacement parts needed**
Annualized Cost	0	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2 years		
CRF	0.0000		
Rep part cost per unit	0 $/ft^3		
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	0	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0		

Electrical Use		kW
NOx in	0.20 lb/MMBtu	
NSR	0.60	
Power		[redacted]
Total		61.0

Reagent Use & Other Operating Costs			
NOx in	0.20 lb/MMBtu	Urea Use	[redacted] lb/hr
Efficiency	25%	Volume 14 day inventory	269 ton
Duty	6,015 MMBtu/hr	Inventory Cost	$134,484
Water Use	[redacted] gal/hr		

Direct Operating Cost Calculations — Annual hours of operation: 7,652.6; Utilization Rate: 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	34.30207	ton/hr	262,500	1,941,450	7.3960 $/ton X 34.3021 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	27.11497	ton/hr	207,500	2,552,250	12.3 $/ton X 27.1150 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500.0 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,236,800
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								11,793,820
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,634,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								3,621,015

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	4,688

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,600,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,008,000
Freight	5.00% of purchased equipment cost	180,000
Purchased Equipment Total	[redacted]	5,148,000
Purchased Equipment Total+ Retrofit Factor (A)		8,236,800
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,702,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,428,800
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	97,020
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	11,793,820
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		11,793,820
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	176,907
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310 See Direct Operating Cost Calculations on last pg.	6,570
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA	-
Total Annual Direct Operating Costs		2,634,116
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		3,621,015

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost	
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			[redacted]
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	[redacted]	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	[redacted]	gal/hr			

Direct Operating Cost Calculations			Annual hours of operation:		8,409.6		
			Utilization Rate:		100%		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,236,800
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								11,793,820
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,852,291
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								5,839,190

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	7,559

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,600,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,008,000
Freight	5.00% of purchased equipment cost	180,000
Purchased Equipment Total	[redacted]	5,148,000
Purchased Equipment Total+ Retrofit Factor (A)		8,236,800
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,702,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,428,800
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	97,020
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	11,793,820
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		11,793,820
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	176,907
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310 See Direct Operating Cost Calculations on last pg.	6,570
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	5.44 See Direct Operating Cost Calculations on last pg.	637,648
NA	NA	-
Ammonia Mitigation	5.61 See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	765,675
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA	-
Total Annual Direct Operating Costs		4,852,291
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		5,839,190

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst			<- Enter Equipment Name to Get Cost
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	\$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0		Cost adjusted for freight & sales tax
Installation Labor	0		Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0		**Zero out if no replacement parts needed**
Annualized Cost	0		

Replacement Parts & Equipment:			<- Enter Equipment Name to Get Cost	
Equipment Life	2	years		
CRF	0.0000			
Rep part cost per unit	0	\$/ft^3		
Amount Required	0	Cages		
Total Rep Parts Cost	0		Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0		10 min per bag, Labor + Overhead (68% = \$29.65/hr)	
Total Installed Cost	0		**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0			

Electrical Use			kW
NOx in	0.15	lb/MMBtu	
NSR	0.44		
Power			[redacted]
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	[redacted]	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	\$97,020	
Water Use	[redacted]	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** 8,409.6 — **Utilization Rate:** 100%

Item	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	\$/Hr	0.0	hr/8 hr shift	0	0	\$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	\$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 \$/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	\$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 \$/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	\$kgal	0.00000	gpm	0	0	\$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	\$/kscf	0.00000	scfm/kacfm**	0	0	\$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	\$/kgal	0.00000	gpm	0	0	\$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	\$/kgal	0.00000	gpm	0	0	\$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	\$/ton	13.94240	ton/hr	117,250	637,648	5.4384 \$/ton X 13.9 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	\$/ton	0.00000	ton/hr	0	0	\$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	\$/ton	17.27193	ton/hr	145,250	814,853	5.6 \$/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	\$/ton	7.40225	ton/hr	62,250	765,675	12.3 \$/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	\$/ton	0.00000	lb/hr	0	0	\$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	\$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 \$/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: Unit 2

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									[redacted]
Purchased Equipment Total (B)									8,236,800
Installation - Standard Costs									1,230,000
Installation - Site Specific Costs									1,008,000
Installation Total									1,702,000
Total Capital Investment (TCI) = DC + IC									**11,793,820**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							7,127,816
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**8,114,715**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	10,505

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. [redacted]
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,600,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,008,000
Freight	5.00% of purchased equipment cost	180,000
Purchased Equipment Total	[redacted]	5,148,000
Purchased Equipment Total+ Retrofit Factor (A)		8,236,800
Indirect Installation		
General Facilities	See footnote 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See footnote 1 on pg. 1 of Table	
Process Contingency	See footnote 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See footnote 1 on pg. 1 of Table	1,702,000
Project Contingeny (C)	See footnote 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,428,800
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See footnotes 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See footnote 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	97,020
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	11,793,820
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		11,793,820
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	176,907
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310 See Direct Operating Cost Calculations on last pg.	6,570
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	7.40 See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA	-
NA	NA	-
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA	-
Total Annual Direct Operating Costs		7,127,816
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		8,114,715

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.08368

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5 years	
CRF	0.2342	
Rep part cost per unit	0 $/ft^3	
Amount Required	12 ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	0	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2 years		
CRF	0.0000		
Rep part cost per unit	0 $/ft^3		
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0		

Electrical Use		
NOx in	0.15 lb/MMBtu	kW
NSR	0.44	
Power		[redacted]
Total		44.0

Reagent Use & Other Operating Costs			
NOx in	0.15 lb/MMBtu	Urea Use	[redacted] lb/hr
Efficiency	20%	Volume 14 day inventory	194 ton
Duty	6,022 MMBtu/hr	Inventory Cost	$97,020
Water Use	[redacted] gal/hr		

Direct Operating Cost Calculations — **Annual hours of operation:** 8,409.6 — **Utilization Rate:** 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.31 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

SNCR Evaluation for Coal Creek Station

URS

COAL CREEK STATION
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
COST AND PERFORMANCE REVIEW

UNDERWOOD, MCLEAN COUNTY, NORTH DAKOTA

PROJECT NUMBER 28966-007

GREAT RIVER ENERGY®
A Touchstone Energy Cooperative

URS ENERGY & CONSTRUCTION
7800 E. UNION AVE., SUITE 100
DENVER, CO 80237

Revision: 0

Status: Final

Introduction

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide; an estimate of the current capital cost for the installation of SNCR, operating and maintenance costs for SNCR, and the level of NOx reductions that can be achieved by SNCR.

The CCS units are identical 605 MW (gross - nominal) CE tangentially-fired furnaces burning North Dakota lignite. Each unit is equipped with Low NOx Burners (LNB) and Over-Fire Air (OFA). Unit 2's LNBs are 2nd generation technology while Unit 1's are the 1st generation installation. Unit 1 currently has a NOx emission rate of 0.20 lbs/MMBtu while Unit 2's NOx emission rate is 0.16 lbs/MMBtu.

The Final Best Achievable Retrofit Technology (BART) analysis submitted in 2007 was based on an inlet NOx concentration of 0.22 lbs/MMBtu and an SNCR removal efficiency of 50%. The current review uses the existing CCS NOx values presented in the previous paragraph and updated removal efficiencies. The following sections present data on SNCR capabilities and cost.

SNCR Capabilities

SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations.

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream. NOx reductions ranging from 25-75% have been reported with SNCR but the higher levels of reduction are only possible with high inlet NOx levels and optimum temperatures and residence time. Typical SNCR performance for utility boilers is in the range of 20-35% NOx reductions.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with fluctuations in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This reduces the effective use of the SNCR system, even when multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Figure 1 shows SNCR NOx removal efficiency as a function of Inlet NOx concentration for 55 existing SNCR installations. The data shows the majority of the installations achieving 20-35% reductions in NOx and only a few installations achieving 50% or greater reductions. There is only one installation achieving 50% reduction at an inlet NOx concentration less than 0.4 lb/MMBtu. This single installation is a cyclone boiler burning a PRB/Illinois coal blend and is the only unit in the data set showing greater than 35% reduction for inlet NOx concentrations less than 0.4 lb/MMBtu.

This figure shows that there are no installations operating with Coal Creek's NOx levels that are achieving greater than 20-25% NOx reductions. The figure also shows that the majority of installations are achieving NOx reductions in the range of 20-30%. Based on the available data, from existing installations operating at the CCS inlet NOx levels used in the BART, the highest level of NOx reduction that could be expected is 30%. At the present CCS NOx levels, it is expected that the highest level of NOx reduction that could be expected is 20%.

Another factor to be considered in the application of SNCR is its effect upon fly ash sales. An ammonia slip of only 5 ppm, which is generally accepted as the minimum that can be achieved in an SNCR application, can render the fly ash produced by the unit unmarketable. CCS currently sells 400,000 tons/yr of fly ash. With SNCR, this fly ash will have to be disposed of in a landfill.

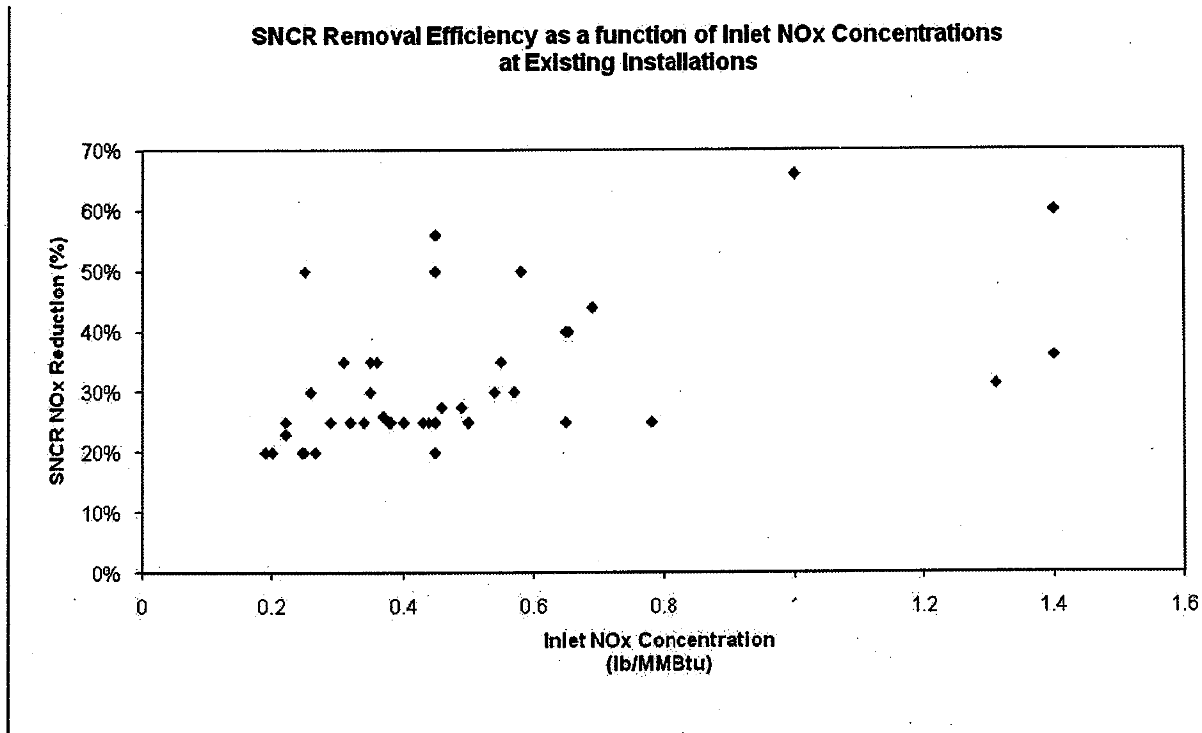

Figure 1 – SNCR Removal Efficiency

SNCR Costs

SNCR capital and operating costs were developed for five (5) different cases utilizing the Electric Power Research Institute's (EPRI) IECCOST model (Rev 3, Nov. 2010) with CCS site specific factors and cost components. The Integrated Emissions Control Cost Model (IECCOST) economic analysis workbook was first published by the Electric Power Research Institute in December 2004. IECCOST produces rough-order-of-magnitude (ROM) cost estimates (stated accuracy of ± 30%) of the installed capital and levelized annual operating costs for Integrated Emission Control (IEC) systems installed on coal-fired power plants. The IECCOST model allows comparison of cost information for conventional and developing SO_2, NOx, particulate, mercury, and integrated emissions control technologies. Costs for utility emission control systems are site-specific, and vary with technology, labor rates, construction conditions and material costs. The site-specific characteristics, operating conditions, process performance requirements and economic criteria serve as input to IECCOST.

IECCOST is able to calculate both new and retrofit plant costs. IECCOST calculates a retrofit factor for each cost area based on site congestion, existence of underground obstructions, soil conditions, seismic zone and state productivity. A series of combustion calculations are carried out based on the ultimate coal analysis provided by the utility and the operating conditions specified for the boiler(s). The resulting flue gas composition serves as the basis for the calculation of a material balance for the control equipment. The material balance provides data for equipment sizing and calculation of the variable operating costs. The process-specific design criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate and waste production rate all are incorporated into the production of each process- and site-specific material balance.

The five (5) cases estimated for CCS are:

1. 0.22 lb/MMBtu inlet NOx with 30% reduction
2. 0.20 lb/MMBtu inlet NOx with 25% reduction
3. 0.16 lb/MMBtu inlet NOx with 20% reduction
4. 0.15 lb/MMBtu inlet NOx with 20% reduction
5. 0.22 lb/MMBtu inlet NOx with 50% reduction

These represent the initial BART assessment NOx rate of 0.22 lb/MMBtu with a commercially achievable reduction of 30% for case 1. Cases 2-4 are representative of CCS's existing NOx emission rates and commercially achievable reductions. The final case is the BART assessment case using 2011 dollars. The costs are for a urea-based SNCR system with 14 days of reagent storage. Urea pricing from a source local to CCS was obtained and the current cost of urea is $500/ton delivered to the site. The general plant input data and IECCOST outputs for SNCR capital and operation and maintenance costs are presented in the following section.

IECCOST DATA

Table 1 – Coal Creek Station Data

General Plant Technical Inputs

Total Gross Rating	MW	605
Gross Plant Heat Rate (GPHR)	Btu/KWhr	9,760
Total Net Rating (Less Auxiliary Power)	MW	572.0
Net Plant Heat Rate (NPHR, Without FGD)	Btu/KWhr	10,500
Plant Capacity Factor	%	90%
TECHNICAL INPUTS FOR BOILER:		
Boiler Heat Input	MMBtu/Hr	5,900
Boiler Heat Output	MMBtu/Hr	4,780
Total Air Downstream of Economizer	%	117.0%
Air Heater Leakage (% of econ. flue gas)	%	7.0%
Air Heater Outlet Gas Temp.	°F	300
Inlet Air Temp.	°F	80
Ambient Absolute Pressure	in. Hg	27.9
Pressure After Air Heater	in. H2O	-11
Moisture in Air	lb/lb dry air	0.013
Carbon Loss	%	0.5%
ASH SPLIT		
Fly Ash or Ash Overhead	%	76%
Bottom Ash	%	24%

Table 2 – SNCR Equipment Sizing

SNCR Equipment Sizing and Capacity Calcs		0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Chosen Reagent		Urea	Urea	Urea	Urea	Urea
Required Reagent Injection	lb/hr	1991	1601	1188	1155	3318
Total Reagent Injection Flowrate	lb/hr	3982	3202	2375	2310	6636
NOx Removed	lb/hr	384	291	186	170	640
NOx Removed	tons/yr	1513	1147	734	670	2522
NOx Emissions	lb/hr	896	873	745	679	640
NOx Emissions	tons/yr	3531	3440	2935	2678	2522
Power Consumption	kW	75	61	45	44	126

Table 3 – Material Costs

SNCR Material Costs		0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year		2011	2011	2011	2011	2011
SNCR Equipment Cost	$	$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor		1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$	$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$	$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$	$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor		1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$	$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$	$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$	$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$	$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$	$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$	$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$	$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$	0	0	0	0	0
Total Plant Investment (TPI)	$	$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$	$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$	$167,000	$134,000	$100,000	$98,000	$280,000
Initial Catalyst and Chemicals	$	$0	$0	$0	$0	$0
Prepaid Royalties	$	$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$	$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$	$0	$0	$0	$0	$0
Power Outage Penalty	$	$0	$0	$0	$0	$0
Land Cost	$	$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outag	$	$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW	21.80	21.10	20.40	20.40	24.00
	Mills/KWh	0.40	0.38	0.37	0.37	0.44

Table 4 – Operation & Maintenance Costs

SNCR O&M Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
Reagent Type			Urea	Urea	Urea	Urea	Urea
Reagent Consumption	lb/hr		1991	1601	1188	1155	3318
	tons/yr		7848	6310	4681	4553	13080
Water	gpm		72	58	43	42	119
Electricity	kW		75	61	45	44	126
NOx allowances generated	tons/yr		n/a	n/a	n/a	n/a	n/a
Reagent Cost	$/yr		$3,924,000	$3,155,000	$2,340,000	$2,280,000	$6,540,000
Water Cost	$/yr		$410,000	$330,000	$250,000	$240,000	$688,000
Additional Power Costs	$/yr		$24,000	$19,000	$142,000	$13,800	$40,000
NOx Credit	$/yr		$0	$0	$0	$0	$0
Total First Year Variable O&M Cost	$/yr		$4,360,000	$3,500,000	$2,600,000	$2,530,000	$7,270,000
Maintenance	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000
Total First Year Fixed O&M Costs	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000

Attachments

URS SNCR Experience
ICAC White Paper – SNCR for Controlling NOx Emissions – 2000
ICAC White Paper – SNCR for Controlling NOx Emissions – 2008 Update

ATTACHMENTS

The following table presents a listing a URS's SNCR experience. Additionally, a partial listing of the Integrated Emission Control (IEC) Technologies that URS has evaluated for the Electric Power Research Institute (EPRI) follows the SNCR experience list.

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit	Location	Size (MW)	Fuel	EPRI	[illegible] in Supplier	New/ Retrofit	Completion Date	Scope
NRG Energy	5 Stations	14 Units	Various	2350	Coal		NA	R	Dec 02	FS, CE
Dayton Power & Light	Total System (6 plants)	15	Various	60-800	Coal		NA	R	1998	FS
Niagara Mohawk	Four Stations	1, 2, 3, 4	NY		Oil, Gas, Coal		NA	R	Dec 94	FS, CE
New York State Electric and Gas	System-wide	10 units	NY	Various	Coal			R	Dec 94	FS, CE
Duquesne Light and Power	System-wide		PA	Various	Coal		NA	R	Dec 93	FS, CE
Atlantic Electric	B. L. England Station			290	Coal		NA	R	Dec 93	FS, CE
Pennsylvania Power & Light	Brunner Island Station	3	PA	790	Coal		NA	R	Dec 93	FS, CE
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	Coal, Oil, Gas		NA	R	Dec 93	FS, CE
Niagara Mohawk	Huntley Station	6, 7	Syracuse, NY	2 x 420	Coal		NA	R	Apr 93	FS, CE

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs Retrofit (R)	Completion Date	Scope
Inland Steel and Nippon Steel (I/N Tek)	Furnaces and Aux. Boiler Continuous Galvanizing Line (9,000,000 tons/yr capacity)	N/A	IN	N/A	Gas		NA	N	Dec 92	FS, CE
Centerior Energy				72 thru 680	Coal			R	1992	FS, CE
Allegheny Energy Supply	Harrison Station	1, 2, 3	Shinnston, WV	3 x 685	Coal		NA	R	1992	E
San Diego Gas & Electric	System-Wide NO_X Compliance	13 Units	CA	Various	Various		NA	R	1991	PE
Entergy Services, Inc.	System-Wide NO_X Reduction Assessment	54 Units	Various	Various	Various		NA	R		FS
Chevron	El Segundo Refinery		CA		Refinery off-gas		NA	R		FS, CE
AES	Warrior Run	1	Cumberland, MD	180	Coal		NA	N	1998	E, P, C
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	T-fired oil and coal Wall-fired oil and gas		NA	R	Dec 93	E
Tennessee Valley Authority	Johnsonville	6 units	Johnsonville, TN	6 x 100	Coal		NA	R	Dec 92	E
Los Angeles Dept. of Water & Power	Haynes	1, 2	Long Beach, CA	2 x 230	Gas/Oil		Ammonia injection	R	1992	E, C

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit	Location	Size (MW)	Fuel	PRB	[illegible] of Supplier	New/ Retrofit	[illegible] Date	Scope
Air Products	Stockton Cogeneration	1	Stockton, CA	50	Coal		NA	N	1988	D, E, CS
Chevron	El Segundo Refinery				Refinery off-gas		NA	R		FS
Texaco	Los Angeles Refinery		Los Angeles, CA	22	Refinery off-gas		NA	R		FS
Air Products	Cambria County	1	Pennsylvani a		Waste Coal		NA	N		E, P

Legend:

BE	Bid Evaluation	D	Design	S	Startup
C	Construction	E	Engineering	STG	Steam Turbine Generator
CA	Construction Advisory	FS	Feasibility Study	T	Testing
CE	Cost Estimate	OE	Owner's Engineer	PRB	Powder River Basin Coal
CM	Construction Management	P	Procurement		

Integrated Emission Control Technologies evaluated for EPRI.

Gas Phase Oxidation Systems

Chem-Mod
ECO™
ECO2™
ISCA

Lextran SO_2/NOx/Hg
LoTOx

Low-Temperature Multi-Pollutant Control System (MPCS)
THERMALONOx
Plasma/Electron Beam Systems
EBFGT
e-SCRUB™
Pioneer Industrial Technologies (PIT)
Pulsatech
WOWClean

Combustion Modification/Fuel Processing
Ashworth Combustor
Clean Combustion System (CCS)
Coal Tech
Emulsified Fuel Technology
Green Coal
High-Sodium Lignite-Derived Chars
K-Fuel
K-Lean
Lignite Cleaning System
The Mobotec System
N-Viro Fuel
Oxycombustion
Soot Free Catalyst
WRI Coal Processing

Wet Scrubbing Systems
Airborne

Aqueous Foam Air (AFA) Filter
CEFCO
Dry-Wet Hybrid Electrostatic Precipitator (ESP)
DynaWave
Eco Technologies
Envirolution/PureStream Gas-Liquid Contactor
FLU-ACE
Integrated Flue Gas Treatment
Integrated Advanced Tower
Ispra by SRT Group
LABSORB
Membrane Wet ESP
MercOx
PEA
Rapid Absorption Process (RAP)/Dry Absorption Process (DAP)
SkyMine

Dry Technologies
Argonne Spray Dryer
NOxOUT CASCADE / Turbosorp Technology (formerly CDS/SCR)
ClearGas Dry Scrubber
Copper Oxide
EMx (previously SCONOx/SCOSOx)
Indigo MAPS
Kuttner Luehr Filter Technology
Low Temperature Mercury Control (LTMC)
Novacon
PahlmanTM Process
ReACT Technology
SNOX

SOx-NOx-Rox Box (SNRB)
Trona Injection

<u>Other Technologies</u>
Argonne Hg/NOx Process
CANSOLV SO2/CO2 Process
GreenFuel
Integrated Pollutant Removal (IPR)
Low Temperature Sulfur Trioxide Removal System (LT-STRS) / Mitsubishi Mercury Treatment System (Mi-MeTS) (Previously MHI High Efficiency System / HCl Injection)
TIPS
Combined Plasma Scrubbing Technology (CPS)
Consummator
ECOBIK
Aqua Ammonia Process
BioDeNOx
Fungal Bioreactor
Plasma Enhanced ESP
ElectroCore

Appendix C

Fly Ash Storage and ASM Technology Evaluation

REPORT

FLY ASH STORAGE AND AMMONIA SLIP MITIGATION TECHNOLOGY EVALUATION

Great River Energy

Coal Creek Station

Submitted To: Great River Energy
Coal Creek Station
2875 Third Street SW
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Distribution: 4 Copies – Great River Energy
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November 15, 2011

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Golder Associates

EXECUTIVE SUMMARY

Great River Energy (GRE) has requested that Golder Associates Inc. prepare a third-party review of potential ammonia slip mitigation (ASM) technology and cost comparisons for associated RCRA Subtitle D ash storage facility design for their Coal Creek Station (CCS) located in Underwood, North Dakota.

These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. As part of the FIP process, the North Dakota Department of Health (NDDH) has requested that GRE prepare a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions, specifically evaluating the application of selective non-catalytic reduction (SNCR) emission control technology. Due to the potential for unreacted ammonia in the flue gas downstream of the SNCR (ammonia slip) reacting with sulfur compounds to form ammonia sulfates that deposit in the fly ash, there is concern over the significant impact on current fly ash sales. Therefore, GRE is evaluating an ASM technology at CCS as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash. This ASM technology is not proven for lignite derived fly ash and is presented as a potential option to reduce the impact of an SNCR on fly ash management. This evaluation includes an ASM technology cost estimation, fly ash disposal cost comparisons, and evaluation of the total cost impact of an SNCR on fly ash management at CCS.

Golder recently visited the Eastlake Station where Headwaters Energy Services' patented ASM technology is currently applied to manage ammonia levels in the fly ash. Based on this operation and Golder's knowledge of CCS and lignite coal-fired power plants, a cost estimate to apply ASM at CCS was prepared. The cost estimate includes costs for the ASM infrastructure including engineering and design, construction, and operations and maintenance. Costs are based on 2011 dollars and capital costs are annualized for a 20-year life and 5.5% interest rate. Existing fly ash sales infrastructure and operations and maintenance are not included in the cost estimate. ASM post-processing costs are estimated to be $5.61 per ton of fly ash treated.

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder prepared a cost estimate for three potential operating scenarios: Scenario A – fly ash sales equal to the average sales over the past few years, Scenario B – ammonia slip impact of an SNCR makes fly ash at CCS unsalable, and Scenario C – ASM technology will be viable for ammonia impacted fly ash at CCS allowing a reduced amount of fly ash sales. A summary of the total estimated fly ash disposal costs is shown in the following table.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The landfill design included the specific size, location, infrastructure, liner, and cover relevant to each scenario. Costs for each scenario included the specific landfill design, engineering, and permitting costs, land acquisition, infrastructure development, liner construction, post-closure care, construction management and construction quality assurance (CQA), GRE internal costs, project contingencies, and operational costs. Based on the annual disposal cost estimate shown in the table above, the potential impact of an SNCR on the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

The total cost impact of an SNCR on fly ash management at CCS includes ASM post-processing costs, fly ash disposal costs, and the loss in revenue generated from the sale of fly ash. Golder evaluated this total cost impact for each scenario, and is summarized in the table that follows. Based on this evaluation, the total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder prepare a third party review of ammonia slip mitigation technology, and cost comparisons for associated RCRA Subtitle D ash storage facility design for Coal Creek Station (CCS) located in Underwood, North Dakota. These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. Based on the proposed FIP, GRE is evaluating selective non-catalytic reduction (SNCR) control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, and higher ammonia in fly ash. Due to the significant impact on current ash sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Headwaters Energy Services. In addition, GRE is evaluating three potential management scenarios for fly ash based on the potential impact of ammonia concentrations to the sale of fly ash.

Golder performed a third party review and estimated costs associated with implementation of Headwaters' ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that "Headwaters has not conducted any field scale assessment on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of field trials is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station," per an email from Rafic Minkara (Headwaters) to John Weeda (GRE) on July 15, 2011.

Golder also prepared a cost comparison for three fly ash storage facility scenarios:

- Scenario 1: CCS's current fly ash sales rate (most fly ash sold);
- Scenario 2: No fly ash sales;
- Scenario 3: Application of ASM technology (allowing for some fly ash sales).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility that meets EPA RCRA Subtitle D type regulations.

1.1 Qualifications

Golder Associates Corporation is an international employee-owned consulting engineering company specializing in the application of earth sciences and engineering to environmental, natural resources, and civil engineering projects. Operating since 1960, our company maintains a network of approximately

160 offices. Current worldwide employment exceeds 7,000 people. The United States operating company, Golder Associates Inc., employs approximately 1,200 people in 51 offices.

This project was conducted by a team based in our Denver, Colorado and Fort Collins, Colorado, offices. The project team was well-suited to perform the proposed services at CCS because of the experience of our technical staff on comparable projects, and our familiarity with the geotechnical and engineering properties of Subtitle D landfill designs. In addition, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationally, including ongoing rulemaking efforts by the EPA.

2.0 BACKGROUND

2.1 Regulatory Basis

In order to attain and maintain the National Ambient Air Quality Standards (NAAQS) within a state, state air quality agencies prepare State Implementation Plans (SIP) for EPA approval. If EPA disapproves of the SIP, either partially or fully, EPA will develop a Federal Implementation Plan (FIP) to address the deficiencies in the SIP.

On September 21, 2011, EPA proposed to partially disapprove the North Dakota SIP, specifically addressing regional haze and proposed a FIP to address the deficiency "concerning non-interference with programs to protect visibility in other states"[1]. As part of this process North Dakota Department of Health (NDDH) has requested a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions. This analysis was submitted by GRE in 2007 and additional evaluations and response to questions were submitted in 2010 and on July 15, 2011 to NDDH. NDDH is requesting additional analyses of selective non-catalytic reduction technology. This report does not include an SNCR evaluation, but provides a cost evaluation to address the potential impact the installation of SNCR would have on the existing GRE fly ash storage and sales.

2.2 SNCR and Ammonia Slip

Selective non-catalytic reduction (SNCR) technology is a post-combustion technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reagent, such as urea, is injected into the post-combustion flue gas. The injection causes mixing of the reagent and flue gas while the heat in the flue gas provides energy for the reaction. The primary byproduct of the reaction is nitrous oxide (N_2O), which is a potent greenhouse gas (GHG).

Unreacted reagent in the flue gas downstream of the SNCR is called slip. This unreacted reagent will appear as ammonia, and reacts with sulfur compounds (from sulfur containing fuels) to form ammonia sulfates which deposit on the fly ash that is collected by the particulate emissions control equipment. The ammonia sulfates are stable in a dry state, but ammonia gas can release if the fly ash becomes wet. Ammonia content in the fly ash greater than 5 parts per million (ppm) (based on Headwaters' experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash.

[1] Federal Register, EPA, 9/21/2011, www.federalregister.gov/articles/2011/9/21/2011-23372

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Headwaters has developed an ammonia slip mitigation (ASM) technology to manage ammonia levels in the fly ash, so that a portion of the fly ash produced can be sold as a concrete additive. The Headwaters' ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was installed at RG&E Russell Station in Rochester, New York in 2004. Russell Station used an SNCR and burned eastern bituminous coal.

The second commercial installation was installed at Eastlake Station in Ohio. Eastlake Station has a 600 megawatt (MW) unit that is fired with a 50/50 blend of Power River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 TPY of fly ash. Headwaters is able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake station. Fly ash is not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Headwaters has not conducted any research on the application of the technology to lignite derived fly ash. Due to the lack of commercial experience with lignite derived fly ash, Headwaters will not provide a guarantee that the ASM technology can be successfully applied to lignite derived fly ash.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of cal-hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. Typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations after treatment of about 35 to 80 ppm.

Golder visited a current commercial application of ASM technology at the Eastlake Station (Figure 1). Fly ash from the electrostatic precipitator (ESP) is sent to one of two fly ash silos where the fly ash is tested daily to determine ammonia concentrations (Figure 2). If the ammonia concentrations are above 150 ppm, the fly ash is diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm are sent to the third silo, after which it is "dosed" with Cal-Hypo and sent to the fourth silo (Figure 3 through Figure 5). The SNCR at Eastlake cannot keep the ammonia slip consistent, and often over-treats a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources is regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia impacted fly ash with Eastlake's ammonia impacted fly ash, Eastlake is able to market approximately 85% of what they produce because this fly ash is considered "treatable" (i.e., ammonia concentration levels are < 150 ppm). Diagrams of the East Lake Station system provided by Headwaters are shown in Appendix A. Subsequent to these diagrams, Headwaters has added a weigh hopper under the silo as shown in Figure 5.

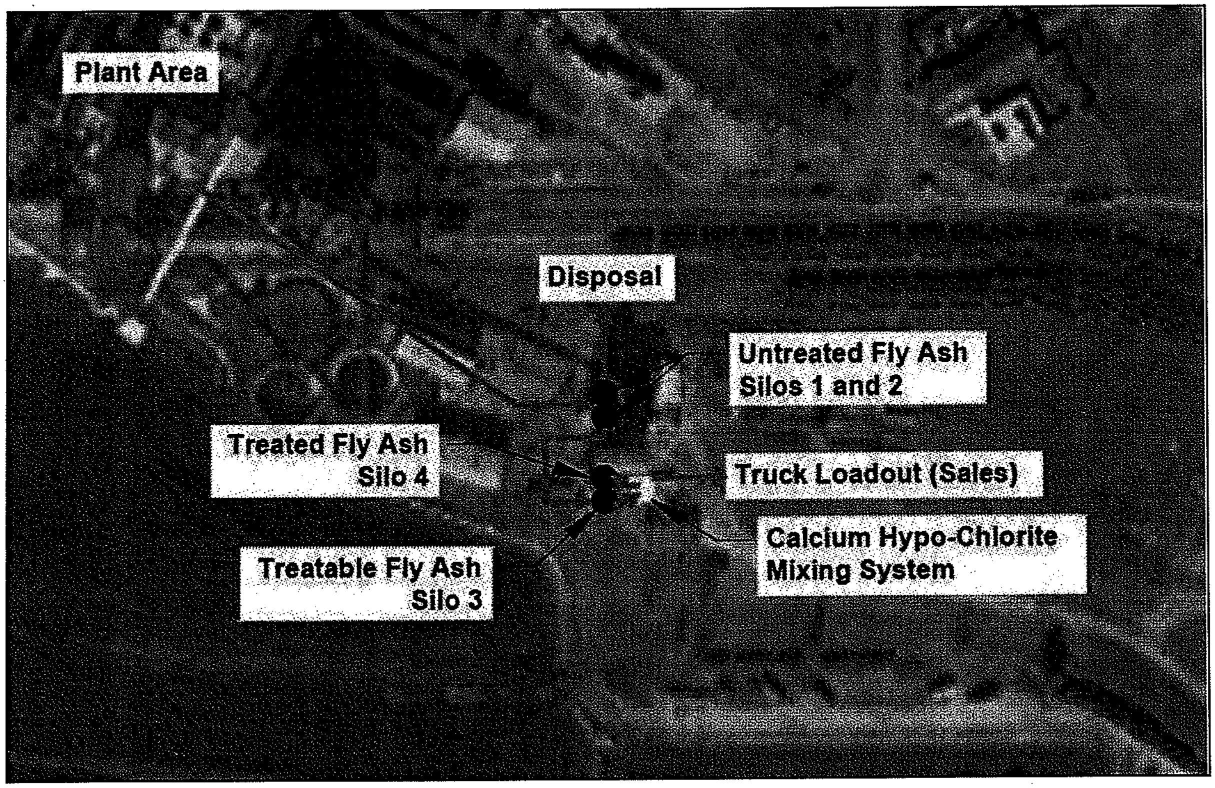

Figure 1: Eastlake Station ASM Schematic

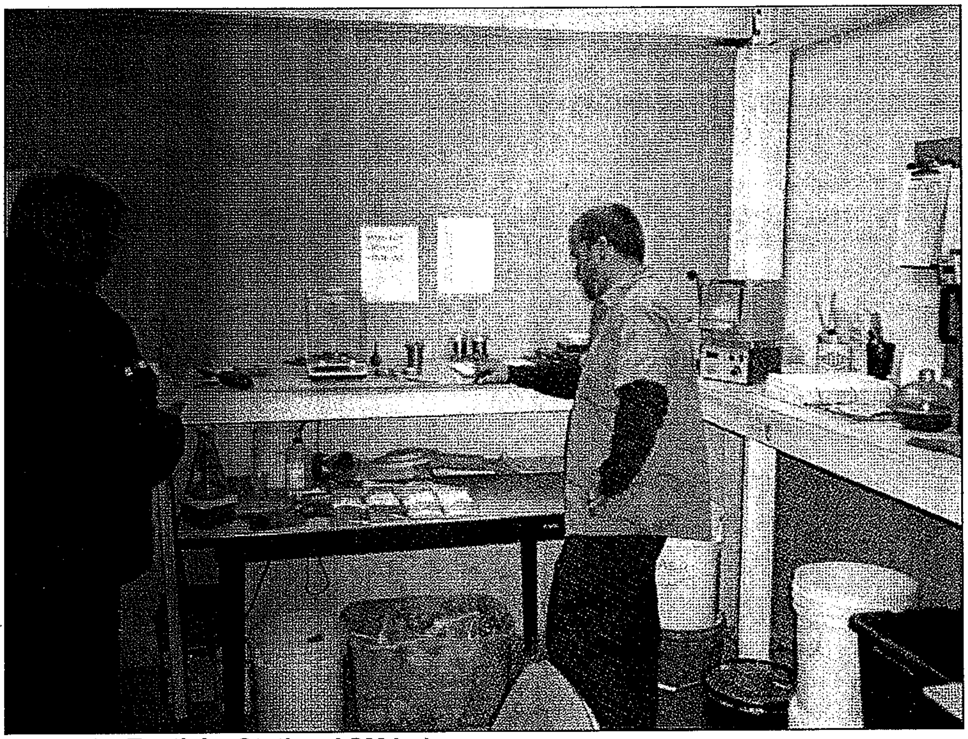

Figure 2: Eastlake Station ASM Lab

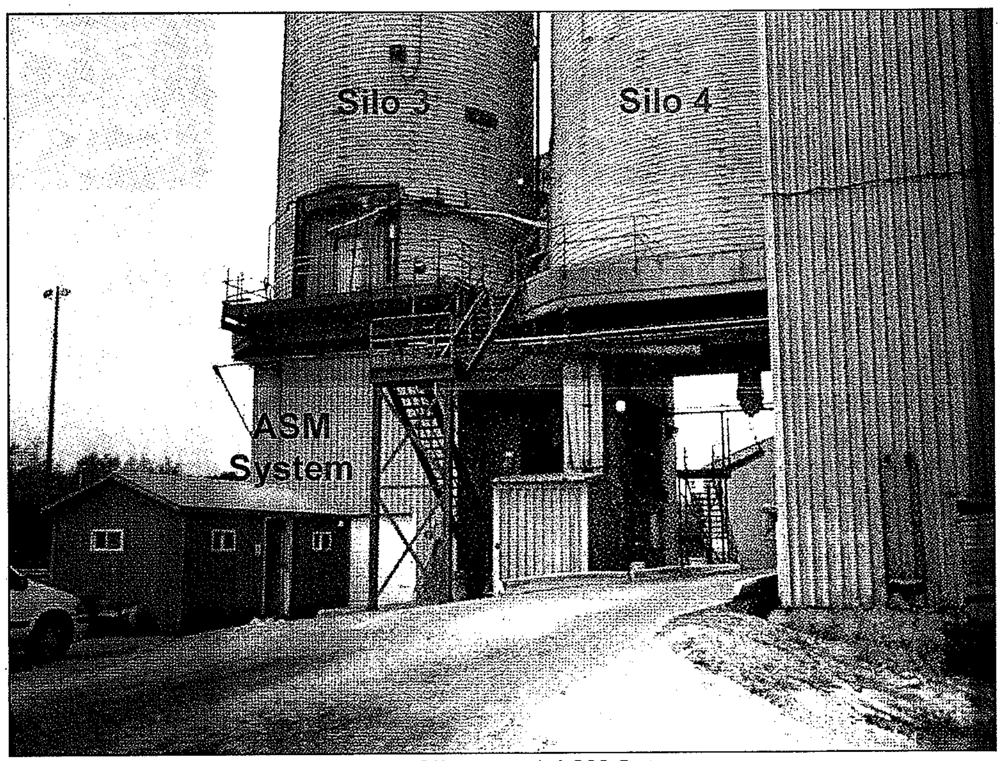

Figure 3: **Eastlake Station** Silo 3, Silo 4, and ASM Setup

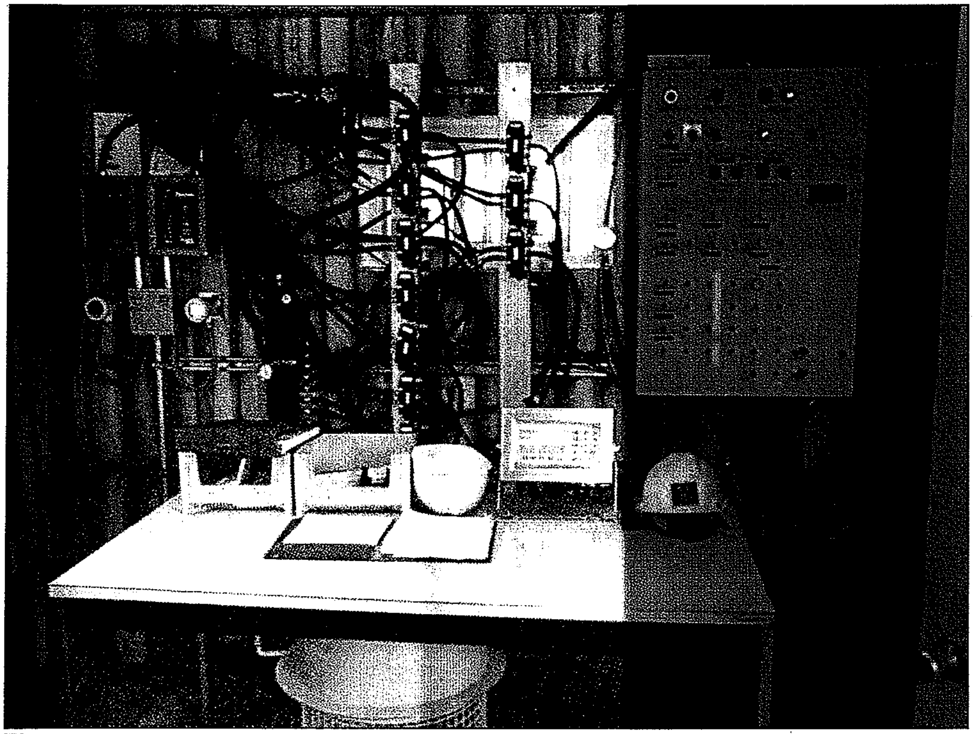

Figure 4: Eastlake Station ASM Control Panel

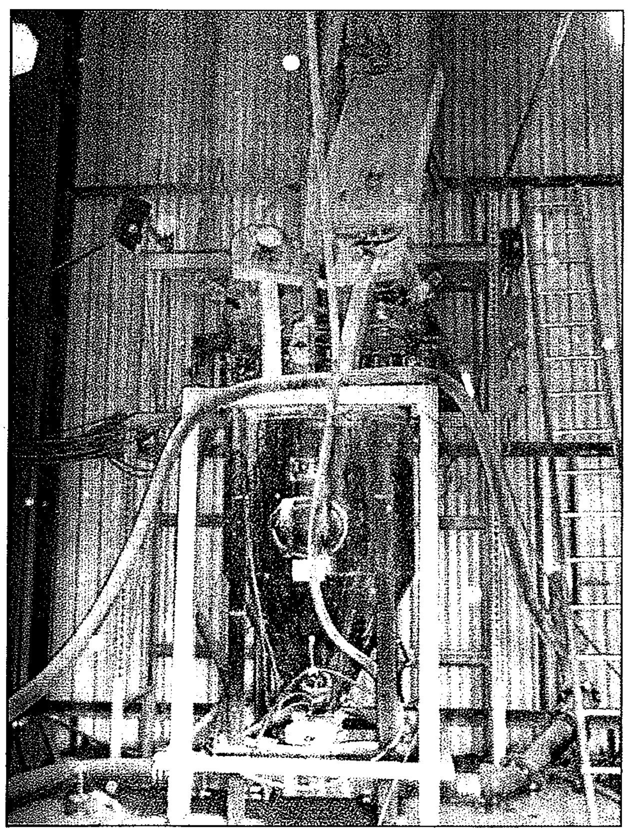

Figure 5: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load "swings," it can be difficult to properly adjust the amount of ammonia injected into the flue gas resulting in varying concentrations of ammonia in the fly ash. If there is a plant upset condition, it may be several days until the ammonia concentrations in the fly ash being produced are at "treatable" levels again. The concern is two-fold. If the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Ammonia gas at low levels is an irritant but can be dangerous to life and health at high concentrations. If too much Cal-Hypo is added, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas even at low concentrations is dangerous to life and health.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 6. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (91 and 92), the rail load-out silo (93), and the fly ash storage dome (94). To utilize ASM, the layout adds a new truck load-out silo south of Silos 91 and 92, and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, the fly ash dome (94) or the rail load-out silo. From these silos, the fly ash is tested, and then mixed with Cal-Hypo as it is loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the exiting truck load-out silos (91 and 92) where it will be loaded into haul trucks and disposed at on-site disposal facilities.

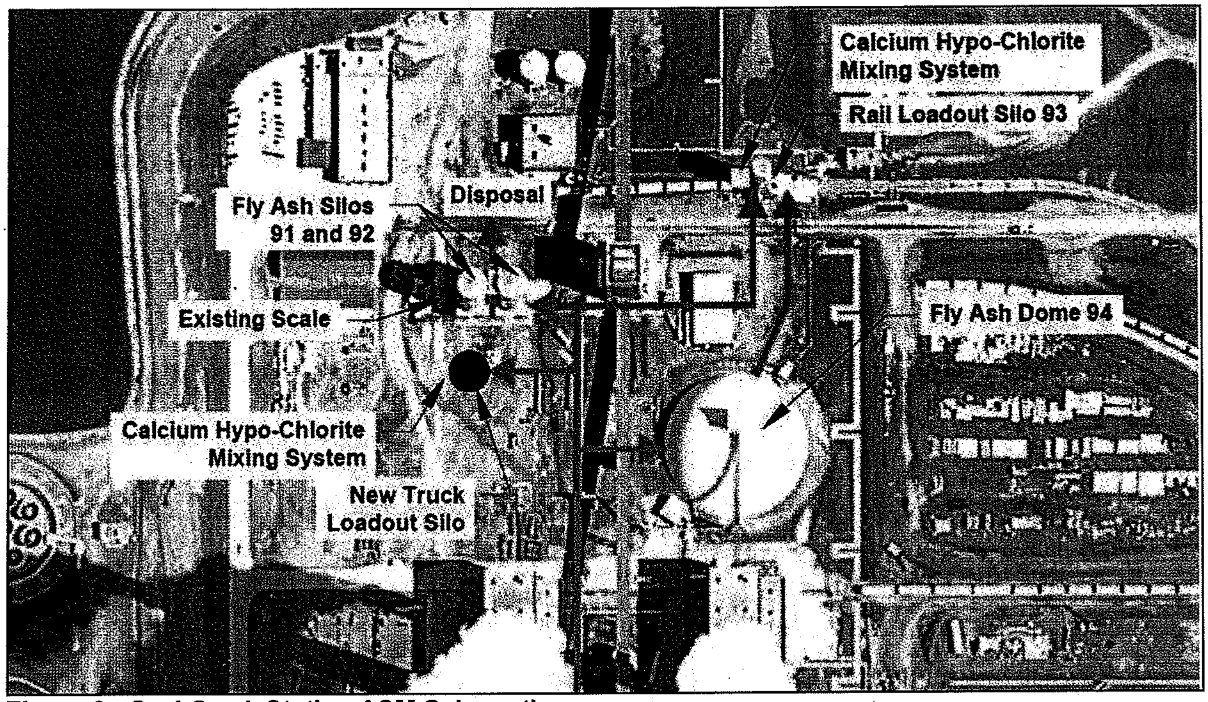

Figure 6: Coal Creek Station ASM Schematic

As discussed earlier, not all of the fly ash coming from the precipitators is expected to be within treatable levels of ammonia. In general, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the fly ash produced should be treatable using the ASM system and will be collected in the rail load silo (93), the fly ash dome (94), or the new truck loadout silo (95). Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentration (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown which results in oily ash.

Golder expects that when any of these conditions occur, the fly ash produced will automatically be directed to the disposal silos (91 & 92). Fly ash will not be redirected to the sales silos (93, 94 or 95) until the upset is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to have less than 150 ppm of ammonia in it.

Based on a review of the recent load profile at CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which will make it untreatable if an SNCR system is installed.

3.5 Cost Estimate

The cost estimate includes costs for the ASM infrastructure including engineering and design; construction; and operations and maintenance. Golder used actual costs from similar projects, and professional judgment to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.

3.5.1 System Engineering and Design

This item is estimated as 10% of the total construction costs to develop the new facilities. Ten percent is based on Golder's professional judgment.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, the silo and handling equipment, dust collection equipment, and feed piping. The costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 7). The total estimated cost for this item is $1.6 million and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide ;
  - Building with the scale and ASM controls
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines;
  - Higher capacity dust collectors to handle the high air flow from ESP.

Details for this cost estimate are included in Appendix B.

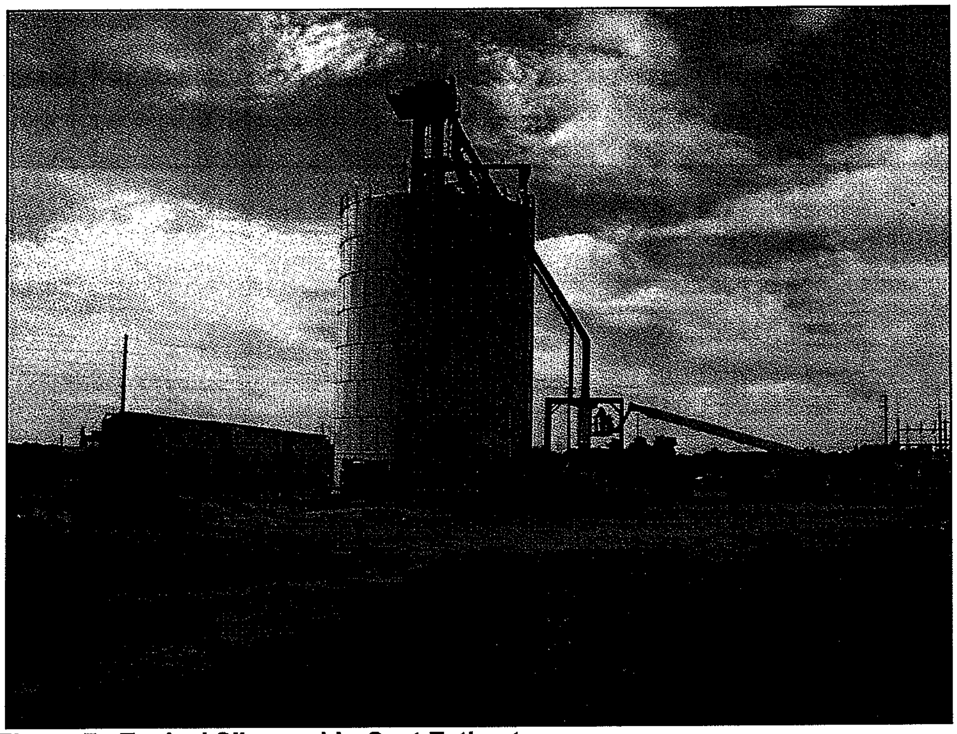

Figure 7: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $574,500 and include:

- Rail loadout silo (93):
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls
- New truck loadout silo (95):
  - Weigh hopper above truck loadout spout;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate a contingency of 15% on the construction costs was added.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at the rail load-out silo (93) and the new truck load-out silo (95).

The estimated cost for this item, based on annual sale/processing of 290,500 tons, is approximately $1.4 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $5.61 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 1 through Table 3, and Figure 8 through Figure 10, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose of fly ash at CCS. These scenarios include:

- ***Scenario A*** – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to make it marketable.
- ***Scenario B*** – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.
- ***Scenario C*** – This scenario assumes that Headwater's ASM technology will be viable for ammonia impacted fly ash at CCS. However, sales will be reduced from current sales due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 1.

Table 1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is meant to represent a typical or average amount of fly ash produced, sold, and disposed at CCS.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Figure 8 shows a potential location for these new facilities just west of the plant property and represents the approximate footprint required for Scenario A.

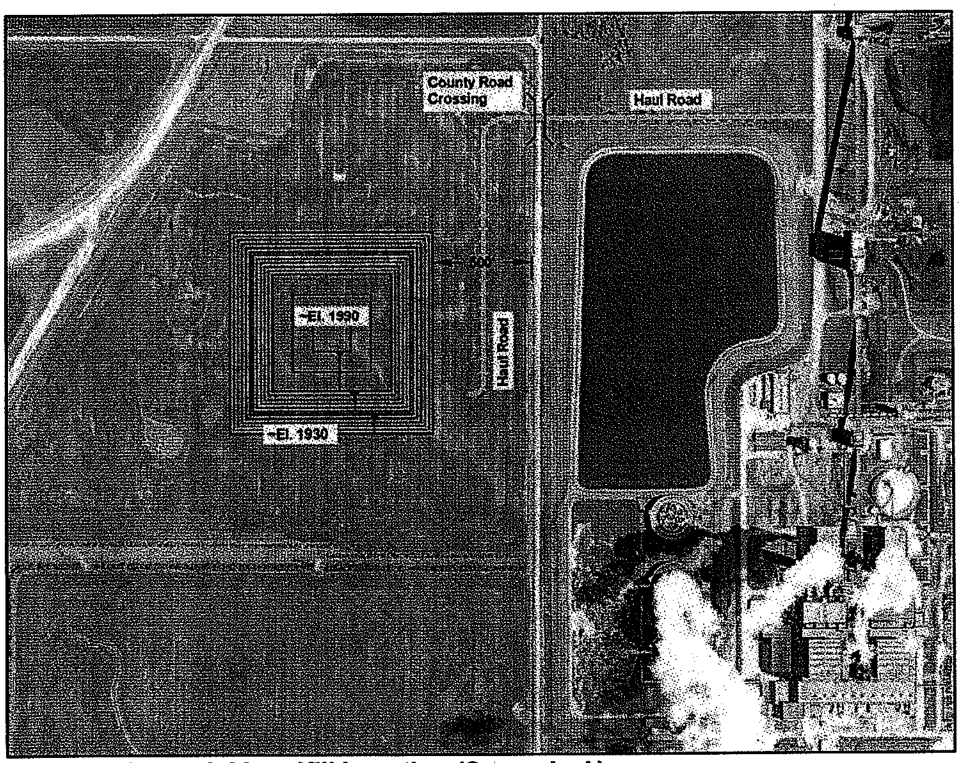

Figure 8: Potential Landfill Location (Scenario A)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios this varies between 2.2 million and 10.5 million tons of capacity. For each Scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, 12-foot high soil berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 75,000 and 118,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the size of each Scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond this lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest whole or partial section of land to the required footprint was assumed.

Table 2 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 2: Scenario Landfill Size

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Liner Acres (acres)	24.0	73.5	41.0
Cover Area (acres)	26.5	81.0	45.0
Site Area (acres)	160.0	240.0	160.0

4.2.2 Infrastructure Development

With the landfill constructed on a new property, considerable site development is required, which may include a haul truck access road, fencing and gates around the property, power to the new site, monitoring wells up- and down-gradient of the new facility, and a water return pipeline to allow the pumping of excess contact water from the site to the ash water tanks within the plant.

In addition, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new country road bridge should be constructed to allow haul truck traffic under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design based on RCRA Subtitle D standards and historic practice at CCS was utilized. The assumed liner system is shown in Figure 9 and consists of (from bottom to top) a compacted clay layer (1×10^{-7} cm/sec maximum permeability), a geomembrane liner, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

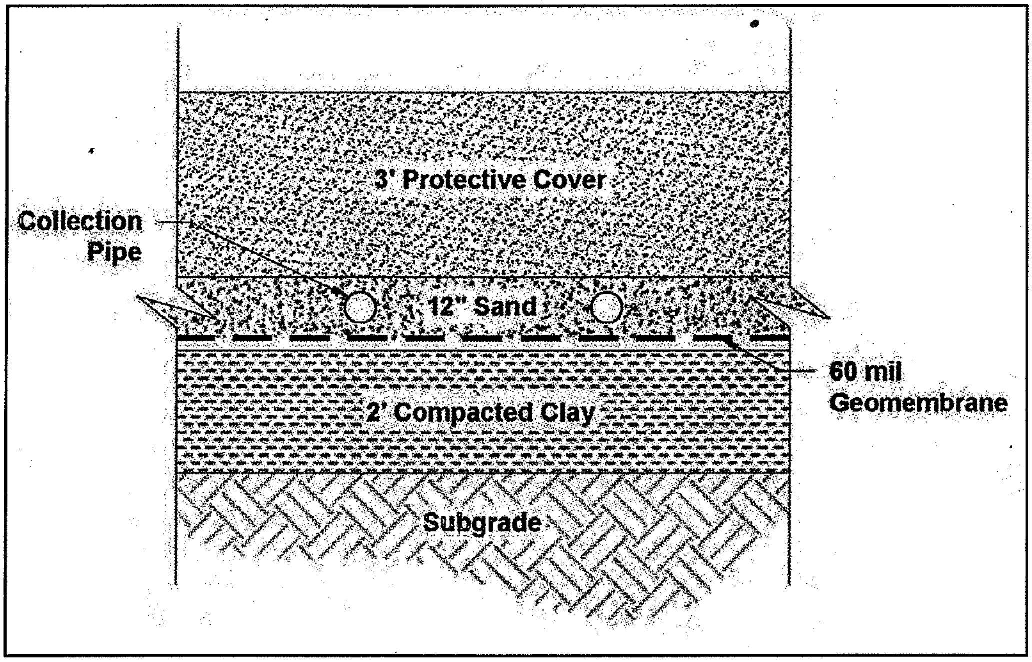

Figure 9: Composite Liner Detail

4.2.4 Cover

The final cover is also design based on RCRA Subtitle D standards and historic practice at CCS. The assumed cover system is shown in Figure 10 and consists of (from bottom to top) a compacted soil layer ($1x10^{-5}$ cm/sec maximum permeability), a textured geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. In addition, the cover will utilize terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

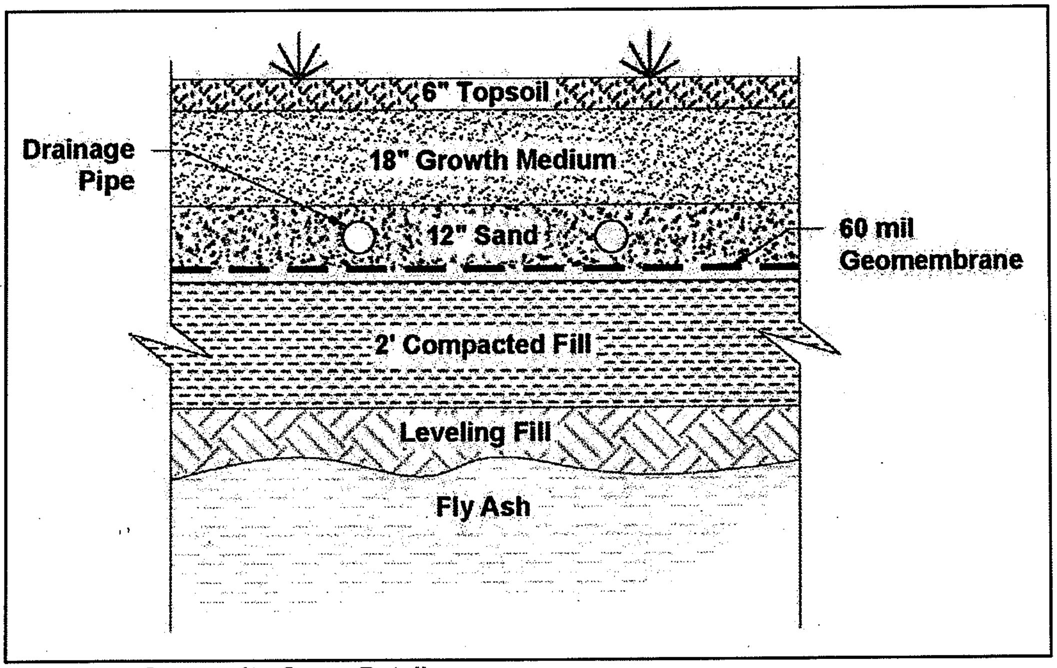

Figure 10: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS.

4.3.1 Engineering, Design, and Permitting

This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit as well as permit renewals, submittal of air permits and NDPES permits, and creation of construction and bid packages for the facility.

Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;
- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;
- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and
- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.

[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.

[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id.* In the final FIP, EPA asserts that SNCR at CCS would not contaminate any fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between $11 and $18 per ton. Golder also demonstrates that EPA's estimate of $5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of $2 to $80 per ton, with an average cost of $59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is $12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

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BARR

Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.

Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Emission Rate Input									
		Stack Velocity	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
NOx Control	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.19
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.19
LNC3+ with Tuning	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1	0.17
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5	0.17
SNCR	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	49%	902.6	0.14
	1 & 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	50%	1806.3	0.14
SNCR with LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2	0.12
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4	0.12

Year 2000 Modeling Results

Description			Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units	Average Improv-ement	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
	1& 2	59%	17	0.217	0.860	16	0.235	0.959	10	0.186	0.596	28	0.376	0.954
LNC3+ with Tuning	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
	1& 2	56%	18	0.251	0.970	18	0.245	0.909	11	0.175	0.627	29	0.426	0.983
SNCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
	1 & 2	86%	5	0.080	0.310	4	0.083	0.290	2	0.056	0.209	3	0.140	0.326
SNCR with LNC3+	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
	1& 2	58%	17	0.235	0.918	17	0.236	0.860	10	0.163	0.605	26	0.409	0.924

Year 2001 Modeling Results

Description			Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units	Average Improv-ement	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
LNC3+	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
	1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
LNC3+ with Tuning	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
	1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
SNCR	1	62%	7	0.101	0.453	7	0.133	0.467	4	0.074	0.433	16	0.192	0.486
	1 & 2	60%	19	0.202	0.884	21	0.267	0.917	12	0.147	0.847	33	0.192	0.486
SNCR with LNC3+	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
	1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417

Year 2002 Modeling Results

Description			Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units	Average Improv-ement	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
	1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
LNC3+ with Tuning	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
	1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
SNCR	1	63%	20	0.193	1.088	14	0.138	0.850	11	0.123	0.692	12	0.148	0.722
	1 & 2	60%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
SNCR with LNC3+	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
	1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement
Pre-BART Protocol	1	1.033	NA	NA	1.151	NA	NA	2.047	NA	NA	1.410	NA	NA
	1& 2	1.890	NA	NA	2.095	NA	NA	3.565	NA	NA	2.517	NA	NA
LNC3+	1	0.438	0.594	0.594	0.515	0.636	0.636	0.947	1.100	1.100	0.634	0.777	0.777
	1& 2	0.842	1.048	1.048	0.885	1.211	1.211	1.806	1.760	1.760	1.178	1.339	1.339
LNC3+ with Tuning	1	0.413	0.620	0.025	0.484	0.667	0.031	0.897	1.151	0.051	0.598	0.812	0.036
	1& 2	0.872	1.018	-0.030	0.833	1.263	0.052	1.713	1.852	0.093	1.139	1.378	0.038
SNCR	1	0.141	0.892	0.272	0.460	0.691	0.024	0.838	1.209	0.059	0.480	0.931	0.118
	1 & 2	0.284	1.606	0.589	0.784	1.312	0.049	1.599	1.967	0.115	0.889	1.628	0.251
SNCR with LNC3+	1	0.362	0.670	-0.221	0.424	0.727	0.036	0.800	1.248	0.038	0.529	0.882	-0.049
	1& 2	0.827	1.063	-0.543	0.731	1.365	0.053	1.529	2.036	0.070	1.029	1.488	-0.140

Appendix E

Low-Baseline NOx SNCR Demonstration (EPRI Study)

This appendix contains confidential business information and is being submitted under separate seal.
Copyrighted material is not currently available for public release.

Appendix F

URS SNCR Evaluation Supplement

URS

March 30, 2012

Debra Nelson
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369

RE: URS Response to EPA FIP Exchange

Dear Debra:

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide:

- A site-specific rough order of magnitude estimate with a stated accuracy of ±30% for the 2011 capital cost required for installation of SNCR onto the Coal Creek units
- Site-specific operating and maintenance costs for SNCR operation at Coal Creek
- The level of NOx reduction expected when using SNCR on these units.

Cost Estimating Methodology - The basis for the cost estimates was stated to be the EPRI IECCOST model, which URS previously developed for the Electric Power Research Institute. This model provides site-specific cost estimates for all types of emissions control system installations, including individual systems that are designed to remove SO_2, NOx, Hg, and particulate matter. It also evaluates costs for multi-pollutant control systems, producing conceptual cost estimates that are site-specific based on the plant location, current operating characteristics, fuels burned, etc.

EPRI IECCOST Model development has continued for more than ten years; during that period URS has installed all of the commercial systems at utility installations, and become intimately familiar with all emissions control technologies. Consequently URS is very familiar with the relationship between the vendor island costs and the Total Capital Requirement for an emissions control retrofit. This extensive project experience also identified the performance capabilities and emission rate guarantees for the various technologies through review of bid documents and budgetary quote submittals under real world conditions.

The model is updated and escalated continuously as new projects are completed, calibrating the cost estimating results against actual project costs and performance. The economic model used for these calculations is IECCOST Version 3.1 that will be published by EPRI later in 2012.

URS Capabilities and Qualifications - URS is an engineering and construction company that has provided emissions control technology assessments, economic analyses, balance of plant designs, construction, construction management and startup assistance to utility and other industrial clients since the 1970's. During this period, URS participated in more than 30 SNCR projects at multiple sites using systems supplied by multiple vendors.

Total Capital Requirement Cost Estimates - URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls interface,

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Denver, CO 80237
Tel: 303.843.3179

interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

Retrofit Factor - A site visit was made to the Coal Creek plant by one of the URS air quality control engineering staff. Based on his assessment of the site and the location for installation of the SNCR equipment, the retrofit difficulty for this plant was established to be moderately difficult due the constraints provided by existing equipment at the plant. Based on previous industry assessments of the cost impacts of retrofit difficulty, a retrofit factor of 1.6 was established for this moderately difficult SNCR installation. Previous industry surveys by Radian and Kellogg (EPA-450/3-74-015 – "Factors Affecting Ability to Retrofit FGD Systems" & EPA R2-72-100 – "Applicability of SO_2-Control Processes to Power Plants" and the EPA/600/S7-90/008 – "Verification of Simplified Procedure for Site-Specific SO_2 and NOx Control Cost Estimates") attempted to quantify the retrofit cost impacts compared to new equipment installations. These surveys established retrofit factors based on retrofit difficulty that are multiplied times the new plant installed cost estimates to determine the retrofit installed cost. The site assessment by the URS staff resulted in the moderately difficult retrofit assessment, which was translated in the capital cost estimate as a 60% adder to the new equipment installation cost to account for decreasing productivity due to movement of parts and materials around existing equipment and structures, limited access to construction sites due to overhead, underground and side obstructions by existing equipment, crane access, etc.

SNCR Expected Performance – SNCR system performance is directly impacted by the flue gas temperature at the point of urea/ammonia injection, and by the current concentration of NOx in the outlet flue gas. Injection outside the correct temperature window results in significant reductions in reduction efficiency. The lower the current NOx concentration in the outlet flue gas, the lower the reduction efficiency that can be achieved (reduced driving force for the NOx reduction reactions). The performance claims in published articles are typically short term, optimized test results, and are typically inflated compared to the performance guarantees that are actually offered for actual installations. Given the relatively low NOx concentrations in the Coal Creek flue gas, the reduction capabilities of SNCR were set at values in the 20-30% range based on data from other recent projects. The urea feed rate used in the calculation of operating costs

For comparison, recent FuelTech papers (one of the major SNCR vendors) stated that larger utility boilers (such as exist at Coal Creek at 605MW) have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 20 – 30% are common for units that start with NOx emission rates of 0.15-0.25 lbs NOx/MMBtu. Urea injection rates to obtain these reduction efficiencies varied from site to site, but fell in the range of 1.1-1.5 normalized stoichiometric ratio while maintaining acceptable ammonia slip rates. All-in costs for these systems were stated to be in the range of $10-20/kW. The injection rates assumed for this URS analysis of SNCR for Coal Creek used NSR injection rates that varied from 1.3-1.5 over the range of control evaluated of 20-30% NOx reduction. All of these performance values and estimated capital costs fall in the ranges stated in the supplier papers.

If you have any additional questions, please contact me.

Sincerely,

Robert J. Keeth
Air Quality Control Group Manager
URS Energy & Construction, Inc.
Denver, CO 80237
303-843-379
robert.keeth@urs.com

Appendix G

Golder Fly Ash Evaluation Supplement

Golder Associates

April 2, 2012 | Project No. 113-82161

Diane Stockdill
Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

RE: SNCR IMPACT TO FLY ASH MARKETABILITY AND MANAGEMENT COSTS

Dear Diane:

1.0 BACKGROUND

Golder Associates Inc. (Golder) submitted a report to Great River Energy (GRE) on November 15, 2011, providing a third party review of Headwater's ammonia slip mitigation (ASM) technology. Additionally, the review included a detailed engineering estimate of potential disposal costs associated with fly ash impacted by ammonia slip from selective non-catalytic reduction (SNCR) emission controls at GRE's Coal Creek Station (CCS).

This report was included as part of GRE's submittal of November 21, 2011 to the U.S. EPA Region 8 (EPA), with comments responding to the Proposed Rule for the Approval and Promulgation of Implementation Plans: North Dakota Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA-R08-OAR-2010-0406).

The EPA provided a prepublication version of the "final rule" to GRE on March 2, 2012, which included EPA's response to various comments including those in GRE's November 21, 2011 submittal:

- Section V: Issues Raised by Commenters and EPA's Responses;
- Part E: Comments on BART Determination;
- Subpart 2: CCS Units 1 and 2;
- Item d: CCS Coal Ash had several comments; and
- EPA responses addressing the potential for SNCR to impact fly ash sales and the cost of this impact.

Below are Golder's responses to the EPA's comments on our November 15, 2011 report concerning the potential impact of SNCR controls to fly ash marketability at CCS and the potential cost impact if fly ash requires ASM technology and is less marketable and therefore, placed in greater quantities into disposal facilities.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles, and the acceptable (allowable) ammonia levels in fly ash by the fly ash end users.

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2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to "restricted use" of fly ash and ammonia slip levels above 4 ppm may lead to "unmarketable" fly ash for use in ready mix.

2.2 Allowable Ammonia Present In Fly Ash

The amount of "allowable" ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Headwaters Resources, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the "...industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable." Headwaters indicated (January 11, 2010) that they "...quit shipping anything over 100 ppm..." in reference to the Eastlake facility, which has had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found "...when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable." Additional references have generally found that approximately 100 ppm is the maximum "acceptable" ammonia level in fly ash (Bittner et al. 2001, Giampi 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces, but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA's permissible exposure limit (PEL) is 50 ppm. A "comfortable" threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water - to - Cement\ ratio)}{(Fly\ Ash\ Content)}$$

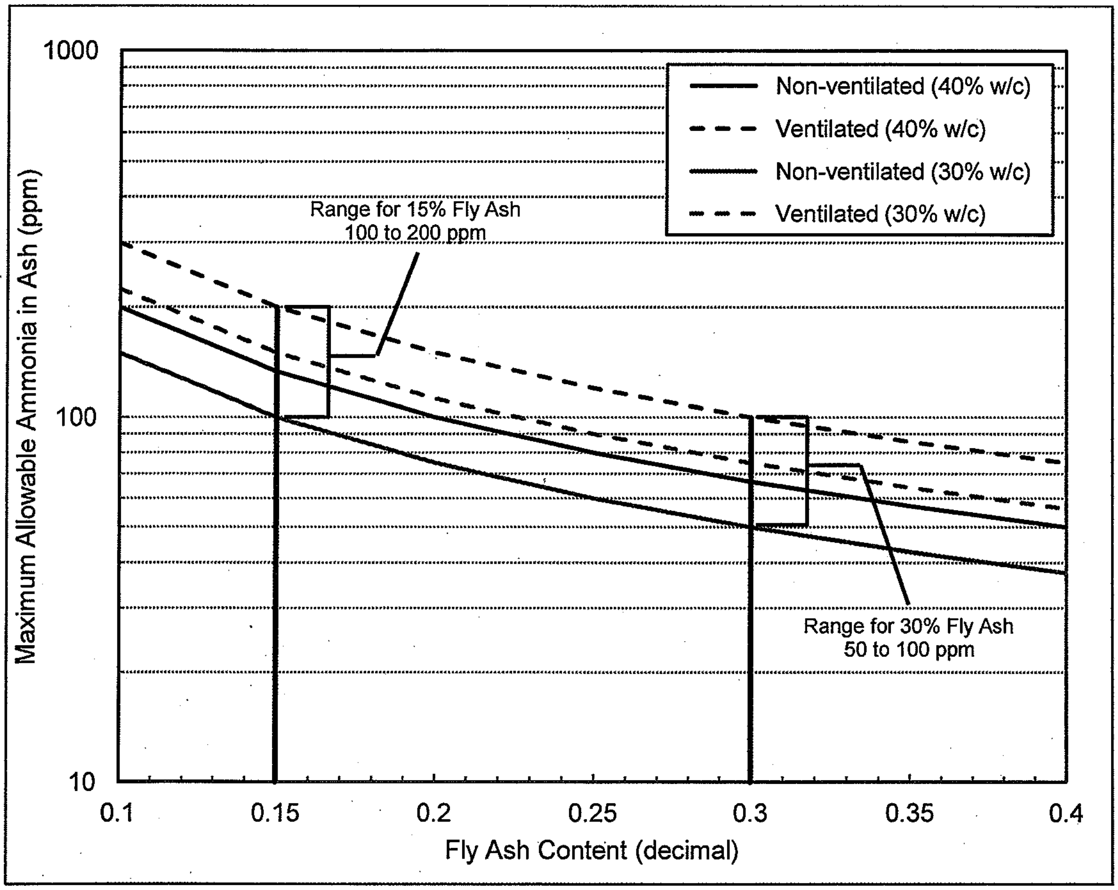
The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in the following table and the figure below.

Condition	Ammonia in Air*	Water/Cement Ratio	Allowable Ammonia Content in Fly Ash (15% fly ash mixture)	Allowable Ammonia Content in Fly Ash (30% fly ash mixture)
	ppm	-	ppm	ppm
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				



2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. Because the ash marketer and ready mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications. This limit is also supported by the anecdotal comments from both Headwaters and Lafarge.

Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering costs evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 SNCR COST IMPACT TO FLY ASH MANAGEMENT

Golder previously provided a detailed engineering cost estimate for the potential impact to fly ash management as a result of SNCR emissions controls at CCS. Based on the EPA responses, supporting information and clarifications are provided below.

3.1 Fly Ash Disposal Facility Design Basis

The previous evaluation indicated that each cost estimate was prepared assuming that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices. This may have been taken as a speculative/highly conservative estimate based on impending coal combustion residue (CCR) regulations being developed by the EPA (see EPA response to comment on page 111 of rule prepublication).

In actuality, the assumed design is based on current North Dakota Department of Health (NDDH) regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html), which are in-line with RCRA Subtitle D practices. In the early 1990s the NDDH revised its Solid Waste Management and Land Protection rules adopting environmentally sound controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring.

3.2 Fly Ash Disposal Unit Cost Estimate

Disposal costs of $11 to $18 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care. In the EPA's responses (page 110), they indicated "we find a disposal cost of $5/ton is reasonable in the improbable event that some ash would need to be disposed."

The cost estimate of $5/ton deemed reasonable by the EPA is not supported by an engineering cost estimate, is not supported by industry information, and is not supported by recent work published by the EPA.

In 2010, the EPA estimated baseline (i.e. current) CCP disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2/ton to $80/ton with an average of $59/ton. In discussion of these results, the report indicates that $2/ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80/ton is reflective of off-site commercial disposal in landfills. Fly ash disposal facilities at CCS are clay- or composite-lined, engineered impoundments and landfills located at varying distances from the plant. North Dakota has comprehensive regulatory requirements in place for ash disposal facilities.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> "As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time." (ACAA, http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $11 to $18 per ton appears well within the EPA's cost estimate and industry practice.

3.3 Lost Fly Ash Sales Revenue

Part of the cost impact to fly ash management is the loss of fly ash sales revenue currently being generated. Based on information from GRE, the 2010 average fly ash sales price per ton was $41.00 with 30% of the sales price going to GRE ($12.30/ton) as revenue and 70% of the sales price going to the fly ash marketer Headwaters ($28.70/ton).

EPA commented that GRE should use $5/ton rather than the updated value of $12.30/ton, and suggested that the lost revenue price included lost revenue to other parties. Based on follow-up discussions with GRE, it was confirmed that the $41/ton is the 2010 average FOB Coal Creek Station sales price and the $12.30/ton portion attributed to GRE does not include lost revenue to other parties. Based on this confirmation, the $12.30/ton rather than the $5/ton is more appropriate for the conditions at Coal Creek Station.

3.4 Cost Impact Conclusions

The fly ash disposal cost estimate is based on an engineering design reflective of the practice in North Dakota, and Golder's engineering estimate of $11 to $18 per ton for fly ash disposal appears to be well within the EPA's cost estimate and consistent with industry practice. Further, the lost fly ash sales revenue of $12.30/ton reported in the cost impact evaluation is reflective of current conditions at CCS.

The disposal and lost revenue cost estimates are valid, and based on the uncertainty with respect to ammonia levels in fly ash, the previous evaluation with respect to fly ash management cost is reasonable.

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Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;

- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;

- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and

- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>**EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis**</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. <u>EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination</u>

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

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[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.
[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.
[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id.* In the final FIP, EPA asserts that SNCR at CCS would not contaminate any fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

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[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between $11 and $18 per ton. Golder also demonstrates that EPA's estimate of $5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of $2 to $80 per ton, with an average cost of $59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is $12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

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Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.